Quantifying a New Horizontal Well Gas Anchor Performance

by

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This research is dedicated to my mom, my dad, and the Liberia Petroleum Refining
Company (LPRC)

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ABSTRACT

Downhole gas separation in horizontal well has been one of the most important research areas in the oil and gas industry for decades. Separating free gas from gas-liquid mixture in the horizontal part of a well before the gas reaches a rod pump system in the vertical part will highly improve the efficiency of the pump. Free gas effects range from lower pump efficiency to reduction in oil production of a well. A new horizontal well gas anchor has been designed and tested experimentally to investigate its separation performance. The test facility used for the experiment is a transparent closed flow loop with horizontal wellbore configurations. Air and water were allowed to flow simultaneously creating a mixture at the inlet of the lateral section of the flow loop. The experiments were conducted in two folds: 1) With the tool in flow loop and 2) Without the tool in the flow loop. The new horizontal well gas anchor has a bull plug at the end, which breaks the wave produced by the mixture and creates a more stable mixture flow that enables gas separation. Also, the tool creates a tortuous path for the gas-liquid mixture and separates gas bubbles in liquid phase of the mixture.

Results from the experiments show that the tool could potentially separate 90 – 100% gas from the gas-liquid mixture given that the tool is fully submerged in the liquid phase of the mixture. Additionally, the separation of gas from the mixture was attained for stratified flow pattern and a superficial gas velocity (v_{SG}) below the established critical (v_{SG}) of 1.4 m/s. The gas separation phenomenon was also observed for experiments that the tool was removed from the flow loop. Separation existed when the inlet of the tubing was fully submerged in the liquid phase. Nonetheless, the bare tubing could not break the wave created by the gas-liquid mixture as in the case of bull plug of the tool. In addition, the upscale analysis was performed to predict the tool performance in the field condition. This allows proper design and installation of the new tool in the field condition.

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PIPING AND INSTRUMENTATION DIAGRAM SYMBOLS

Pressure Regulator
Automatic Control Valve
Submersible pump
Pressure Relief Valve
Ball Valve
Micro-Motion™ MR-Series 050S for Gas
Micro-Motion™ F-Series 100S for Liquid

NOMENCLATURES

Acronyms

ALS	Artificial lift system
BHP	Bottom-hole pressure
BPD	Barrel per day
CS	Capacitance sensor
ESP	Electrical submersible pump
GLRs	Gas-Liquid Ratios
HWGA	Horizontal well gas anchor
ID	Inner diameter
IF	Intermittent Flow
KOP	Kick off point
<i>MW</i>	Molecular weight
OD	Outer Diameter
P	Pressure
PCP	Progressive cavity pump
PT	Pressure Transmitter
QCV	Quick Closing Valves

Q	Volumetric flow rate
R	Universal gas constant
SCF	Standard cubic feet
SCFD	Standard cubic feet per day
SRPS	Sucker rod pumping system
SS	Stratified Smooth
STBL	Stock tank barrel of liquid
STBO	Stock tank barrel of oil
STBW	Stock tank barrel of water
SW	Stratified Wavy
T	Temperature

Roman and Dimensionless Variables

A	Area [m^2]
C	A constant in Blasius type Fanning friction factor equation based on either Re_{SL} or Re_{SG} . 1 for laminar flow $Re < 2100$ and 0.046 for turbulent flow $Re > 2100$
d	Inner diameter of the pipe [m]
f	Fanning friction factor [-]
g	Gravitational acceleration constant (9.81 m/s^2)
h	Liquid Level
L	Length [m]
m	The exponent in Blasius type Fanning friction factor equation based on Re_{SG} .
n	The exponent in Blasius type Fanning friction factor equation based on Re_{SL} .
P	Pressure [Pa]
Re	Reynolds number.
S	Wetted wall circumference [m]
v	Velocity [m/s]
X	Lockhart and Martinelli parameter [-]
x	Mass pickup and shedding rate [kg/s]

Y Inclination angle parameter [-]

Greek Symbols

Δ Delta

θ Inclination angle [degree] ($\theta = 0^\circ$ for horizontal).

μ Gas dynamic viscosity [Pa·s]

ρ Density [kg/m³]

τ Shear stress [Pa]

Subscripts

A Acceleration

C Critical

G Gas

F Friction

f film

L Liquid

I Interface

P pipe

SG Superficial gas

SL Superficial liquid

s Slug body

TB Taylor bubble

TBe End point of the Taylor bubble (film location that meets the slug front)

U Slug unit

W Wall

Mathematical Operators

$\sim$ Tilde sign for dimensionless quantities.

CHAPTER I

INTRODUCTION

Since the introduction of horizontal well drilling technique in the 1900s, the production of oil from unconventional reservoirs has tremendously improved. Horizontal drilling provides a wide range of benefits including the increased in oil recovery efficiency from thin oil reservoirs and higher rate of return from reservoirs (Fleming 1993; Yildiz 2005; Butler 1994; Mulder et al. 1992; Vanorsdale and Vogel 1996). Reservoir pressure plays a significant role in the volume of oil produced from these horizontal wells. When a well is put on production and the reservoir pressure is above the bubble point pressure, a single-phase oil production is observed. As production continues, the reservoir pressure decreases with time. When the reservoir pressure falls below the bubble point pressure, dissolved gas in the oil phase starts to come from solution. This phenomenon creates a two-phase mixture (oil and gas) that flow from the reservoir into the wellbore.

For decades, researchers have been developing different models to explain the behavior of gas-liquid two-phase flow in pipes, and the effect free gas has on oil production. Eghorieta et al. (2018) and Zaghloul et al. (2009) presented different models to predict the behavior of gas-liquid two-phase flow in horizontal pipe. These models also considered the different flow patterns including stratified flow, intermittent flow and dispersed bubble flow associated with gas-liquid two-phase flow in flow lines at various inclination angles. Moreover, Eghorieta et al. (2018) pointed out that a serious consideration of gas-liquid two-phase flow is necessary when predicting which artificial lift method is feasible for a well development.

During the life of an oil well, an artificial lift system might be required at some point in time to optimize oil production. Gas lift, plunger lift, and hydraulic jet pumps work perfectly with large volume of free gas produced from the oil as reservoir pressure declines (Camargo et al. 1997; Clark et al. 2014). Moreover, Jackson (2018) and Clark et al. (2014) suggest that artificial lift techniques like hydraulic jet pumping system can be run in the lateral part of a horizontal well. Nonetheless, gas lift as well as hydraulic jet pump system

are unable to substantially lower the flowing bottom-hole pressure of a well as in the case of a rod pump system. Rod pump system, most widely used artificial lift techniques, has proven to optimize oil production by substantially lowering the sand-face pressure. However, the pumping efficiency is reduced significantly when the sucker rod pump system encountered certain volume of free gas (Rowlan et al. 2007; Phillips et al. 2013). Because of the effects that produced gas has on the rod pump system, many studies have been conducted on downhole gas separation techniques in horizontal well.

Over the years, downhole gas separators including mud anchor, collar size separator and poor-boy gas anchor were designed and remodified to separate gas from gas-liquid mixture in wells (Ryan 1992). Many of these gas anchors were designed to work in vertical well or the vertical part of the horizontal wells. Their working mechanisms have failed to achieve optimal downhole gas separation, thus, affecting the performance and efficiency of the rod pump system in horizontal wells. Watson et al. (2018) proposed a new horizontal well gas anchor. The proposed tool was tested in the field and showed potential separation of gas from gas-liquid mixture within the lateral part of a horizontal well (Watson et al. 2018). Research efforts on downhole gas separation within the lateral section of horizontal wells are still ongoing.

1.1 Main Objective

The main objective of this research is to quantify the performance of a new horizontal well gas anchor installed at the heel of a horizontal flow loop. To achieve this goal, experimental study was performed under various conditions including different flow rates and inclination angles. The inclination angles used for the experiment are -2° , -1° , 0° , $+1^\circ$ and $+2^\circ$. There are two working mechanisms of the new gas anchor by which it performs separation. The first working mechanism is that the bull plug of the tool breaks the wave produced by the gas-liquid mixture and creates a somehow stable flow. The second working mechanism is the tortuous path created by the tool to facilitate small gas bubble separation in the liquid phase of the mixture. However, this experimental study only investigated the new gas anchor performance based on the first working mechanism. These

two working mechanisms of the new tool are done simultaneously for the tool to separate gas from the mixture.

1.2 Scope of Work

The scope of this research work is mainly geared toward quantifying the separation performance of the new horizontal well gas anchor. The tests were conducted within a transparent closed flow loop with horizontal wellbore configurations. Other considerations taken into account for the experiment are flow pattern and pressure drop predictions.

1.3 Thesis Overview

The thesis consists of five chapters.

Chapter 1 covers the introduction of the research work. It includes the primary objective and scope of the study.

Chapter 2 comprises of a comprehensive literature review mainly on two phase flow patterns, gas anchor/or downhole gas separators, artificial lift mechanisms, and pressure drop in pipe.

Chapter 3 gives a detailed explanation about the experimental procedures and description of the testing facility used for the experiment.

Chapter 4 provides the experimental results and comprehensive discussion of the outcomes from the results.

Chapter 5 gives the conclusion of the study and recommendations for future research on this topic.

Finally, a section consisting of bibliography and appendices is at the end of this thesis.

CHAPTER II

LITERATURE REVIEW

This chapter provides an in-depth overview on artificial lift techniques, downhole gas anchor, characterization of flow pattern and pressure drop in flow pipe. This section is subdivided into the following:

1. Overview of Artificial Lift Methods
2. Downhole gas anchor literature review
3. Flow pattern characterization
4. Pressure drop in flow lines overview

2.1 Overview of Artificial Lift Systems (ALS)

There are several artificial lift techniques used in the oil and gas industry. Major artificial lift methods include sucker rod pump system, gas lift, progressive cavity pumps, electrical submersible pumps, plunger lift system, and hydraulic jet pumps. The performance of the various artificial lift systems can be monitored and evaluated by operational instrument and software currently available in the oil and gas industry. Various Artificial lift techniques are used globally to improve the production of wells that primary energy source can no longer lift fluids to surface. Inflow and Outflow performance analyses are conducted to determine if a well will need an artificial lift system upon completion.

Hardegree et al. (2018) developed the chamber gas lift, a combination of intermittent and continuous gas lift techniques, and performed an experimental work to investigate its performance. The authors concluded that the new chamber gas lift system sustained a lower downhole pressure than previous gas lift system, increased fluid production as well as exhibiting a good chamber-sweep efficiency (Hardegree et al. 2018). Gas injected into the wellbore by gas lift system reduces the density of fluid, lowers the hydrostatic head on the formation and allows the reservoir pressure to lift the column of fluid to surface (Hearn 2010; Beckwith 2014). This type of ALS requires high pressure gas to be injected from surface to operate.

Another important form of ALS is plunger lift. Foss and Gal (1965) presented a classical investigatory work on plunger lift system. The authors mathematically solved static force balance on the plunger to ascertain the minimum backpressure needed to lift liquid slug to surface (Foss and Gal 1965). Plunger lift is considered one of the ALS for well with high GLRs and low productivity. It does not require input energy for lifting liquid to surface. However, it requires continuous monitoring during operations (Baruzzi and Alhanati, 1995).

Electrical Submersible Pumps (ESP), another form of ALS, has greatly expanded in the oil and gas industry since its debut in 1930 (Bassett 2010). According to Bassett (2010), the placement of the ESP below the perforations can greatly increase the pump intake pressure, as well as maximizing production. The author strongly advised the use of down-hole gas separator below the pump intake to prevent gas from reaching the pump. However, ESPs require high horsepower for lifting operations.

The Progressive Cavity Pumps (PCP) has been one of the key ALS option used in the oil and gas industry. Alfrahih et al. (2016) conducted two different performance analyses on PCP production. The first experiment was done without sand control, while the second was performed under proper sand control. The authors concluded that adding sand control device, like sand screen, below the PCP setting depth can greatly improve the production of a well. Although, all the artificial lift systems mentioned above are used differently to increase well production, nevertheless, they are unable to substantially lower the flowing bottom-hole pressure as much as a rod pump can.

A sucker rod pumping system is the most common form of artificial lift systems used in the US and Venezuela (Watson et al. 2018, Juch and Watson 1969). There has been an attempt to run the rod pump in the curve and lateral part of a horizontal well. Researchers have suggested that the sucker rod will suffer severe wear. The body of the sucker rod pump and sucker rods could rub against the wellbore when placing it in the lateral or curved section of a horizontal well. Henceforth, sucker rod pumps are only run in the vertical section of horizontal wells.

According to Cortines and Hollabaugh (1992), after 1985, Oxy Energy used three ALS (Gas Lift System, ESP, and SPRS) in their horizontal wells in the Pearsall field, South of Texas. Amongst the three ALS used, sucker rod pumping system was found to be effective and efficient in substantially lower the BHP and provided larger volume of oil recovery. However, the efficiency of the sucker rod pumping system is greatly reduced when it encounters free gas.

Allison et al. (2018) stated that the pumping efficiency of a rod pump system is about 70 – 80% when pumping liquid. Nevertheless, when the rod pump experience gas interference, its pumping efficiency drops below 40% (Allison et al. 2018).

The effects of free gas on several artificial lift systems including the sucker rod pumping system have prompted researchers to started developing various down-hole gas separators such as poor-boy gas anchor to alleviate rod pump inefficiency.

2.2 Downhole Gas Anchor Literature Review

Downhole gas separator has been in existence for decades in the oil and gas industry. There were growing concerns in the oil and gas industry about low efficiency of some artificial lift system like rod pump due to gas interference. As such, researchers began digging into ways to separate gas from gas-liquid mixture before the liquid reaches the pump intake. Clegg (1963) stressed that the installation of downhole gas separators such as the natural gas anchor, packer type gas anchor, and poor boy gas anchor, must be carefully planned with special considerations. Hence, several downhole separators such as the poor-boy gas anchor (Gallian 1961 and Ibara et al. 2013), packer-type gas anchor (Clegg 1963 and McCoy et al. 2015) and Don-Nan gas separator (Don-Nan 2011) were developed and improved significantly in the past decades.

Kobylinski et al. (1985) proposed a newly designed rotary gas separator/ anchor that was tested in the field. The authors concluded that using the centrifugal gas separator increased the production at an average of 95% in the eight wells. Moreover, due to the

rotary gas separator performance to separate gas from the liquid, the life of the ESP and equipment was increased to an average of 60 to 70% (Kobylinski et al. 1985).

Campbell and Brimhall (1989) developed a computer program that helps in the designing of gas anchor and determining the efficiency of the gas anchor considering pressure drop calculations. The authors suggested major parameters including length of dip tube, gas bubble velocity, pressure drop associated with the system and diameter of the dip tube to be seriously concern when designing a gas anchor. Although, many of the downhole gas separators/ anchors such as poor-boy gas invented were used in the field, some of these gas anchors have poorly performed to separate gas for gas-liquid mixture in the wellbore. Thus, creating a severe problem for some ALS including ESPs and SRPS. Some newly designed gas anchors have proven to be more efficient to separate gas from gas-liquid mixture.

McCoy et al. (1995) patented a designed and field-testing results of a decentralized continuous flow downhole separator. Prior to the installation of the decentralized downhole separator in the Sprayberry field, the authors pointed out that the well would not pump after a pump change and that the dynamometer cards showed huge gas interference. After the installation of the gas separator, in one week, the well was producing about 286 barrels of liquid and 33 MCF per day. Bohorquez et al. (2009) conducted several experimental studies on some downhole gas separators and suggested that gas could separate if the gas separator body can create mixture velocity less than 6-in/sec and a gas bubble size diameter of 0.25-in.

Don-Nan (2011) patented an innovative designed gas anchor called Don-Nan Gas Separator. The authors provided two case studies conducted in the field that suggest that the Don-Nan gas separator could potentially separate gas from gas-liquid mixture. In the first case study, the authors' indicated that before testing the gas anchor the well-produced oil at 12 BPD. After the Don-Nan gas separator was installed, oil was produced at 42 BPD for the first 30 days. A 30 BPD increased in oil production (Don-Nan 2011). McCoy et al. (2015) conducted several experiments to evaluate the performance and effectiveness of a

packer-type downhole gas separator. They found that the use of packer-type downhole gas separator improved the pump fillage by 10%. This means the separator removed some gas out and allowed more liquid to enter the pump (McCoy et al. 2015).

Most of these gas anchors were built to work in vertical wells. However, Watson et al. (2018) proposed a new gas anchor that can be installed in the lateral section of a horizontal well. This installation gives a greater separation distance from the SRPS. The authors provided field study conducted on the new horizontal well gas anchor (Watson et al. 2018). The authors indicated that prior to the installation of the new gas anchor, the oil production could not exceed 300 BPD. After the installation of the new horizontal well gas anchor, the oil rate went above 500 BPD. This shows an increase of over 200 BPD (Watson et al. 2018). Further developments are needed for downhole gas separator/ anchor to work optimally for two-phase flow in a horizontal well.

2.3 Two-Phase Flow Pattern Overview

Two-phase gas-liquid flow in wells is a function of pressure and temperature. Reservoir pressure plays a vital role in creating the downhole two-phase flow phenomena. Single phase liquid flow is observed as the reservoir pressure stays above the bubble point pressure. As the well keeps producing, the reservoir pressure drops and reaches the bubble point pressure. Then, gas comes out of liquid phase. This forms a two-phase gas-liquid flow. The two-phase gas-liquid flow exhibits different flow patterns as the mixture moves through flow lines and wells. Predicting the flow pattern of a two-phase flow in the wellbore depends on many factors. These factors are the inclination angles, pipe diameter, flow rate of each phase, and physical properties of the fluids (Shoham 2005). Stratified (smooth and wavy), intermittent (slug and elongated bubble), annular and dispersed bubble flows are the common types of flow patterns that exist in horizontal and near horizontal pipes. For vertical and sharply inclined pipes, flow patterns that exist are bubble, intermittent (slug and churn), annular and dispersed bubble flows (Shoham 2005).

Many researchers have proposed different models and ways to predict each flow pattern along the flow line (horizontal, inclined or vertical). Taitel and Dukler (1976)

developed a model for predicting two-phase Newtonian flow in horizontal and slightly inclined pipes between $\pm 10^\circ$. The model was confirmed successful after it was tested with data from small-diameter pipe and low-pressure experiments. Taitel and Dukler Model was used as the basis for establishing the transition boundaries between stratified (smooth and wavy), slug, annular, and dispersed bubble flows. Barnea et al. (1980) performed experimental analyses to determine the flow pattern in two-phase air-liquid flow using electrical probes. They concluded that the flow pattern for any two-phase flow can be easily predicted from data from oscillography traces collected by electrical probes. Barnea et al. (1982) conducted several experiments on gas-liquid two-phase flow for inclination angles ranging from 0 to -90° . They developed a mathematical mechanistic model to predict flow pattern for downward flow conditions (Barnea et al. 1982).

Barnea et al. (1985) expanded the existing downward flow mathematical model to predict the flow pattern for inclination angles ranging from 0 to 90° . This model enables user to predict the flow pattern for horizontal, downward and upward flows' directions. Barnea et al. (1987) developed the comprehensive unified model that incorporates all transition boundaries and applicable for angles ranging from $+90^\circ$ to -90° (Barnea et al. 1987). Xiao et al. (1990) presented a comprehensive mechanistic model that incorporates both unified model for predicting flow pattern and pressure drop models for each flow patterns. This model is used for the different pipeline designs. In recent years, Zhang et al. (2003) proposed a unified comprehensive model that can be used from angles ranging from -90° to 90° mainly for slug flow dynamics.

2.4 Overview of Pressure Drop in Pipes

The pressure drop in flow line is an important aspect of fluid flow in pipelines. Fluid flows in the path of the least resistance. Each flow pattern has a considerable influence on the determination of the pressure drop along the flow line. Many researchers have proposed various ways to determine the pressure drop in flow lines at different flow pattern conditions. Govier and Aziz (1972) presented a graphical model that was developed from data collected from several air-water experiments done at STP in a 2.54-cm (1-in) inner diameter pipe. The graphical model was used to determine the total pressure gradient

associated with different flow patterns in vertical and horizontal pipe flow (Govier and Aziz 1972). The determination of the pressure drop in flow lines for two-phase flow is complex due to the complexity of the flow of the mixture. Correlations as well as closure relationships are used by these models to determine the flow pattern, and pressure drop inside flow lines. There are many available models proposed to determine the pressure drop in flow lines for each flow pattern.

Taitel and Dukler (1976) proposed a model that presents a computational analysis to predict an equilibrium stratified flow. Once the flow pattern is determined, the authors presented series of steps and equations to determine the equilibrium liquid holdup, h_L , in pipe and pressure drop per unit length for stratified flow. The model is only valid for horizontal and near horizontal flows ($\pm 10^\circ$) (Taitel and Dukler 1976). The authors showed that the equilibrium liquid holdup for a horizontal flow depends only on the Lockhart and Martinelli parameter, X . For a non-horizontal flow, the equilibrium liquid holdup depends on both the Lockhart and Martinelli parameter, X , and the inclination angle parameter, Y . These two parameters are dimensionless parameters and the proposed equations are as follows:

$$X = \frac{\sqrt{\left. \frac{dP}{dL} \right|_{SL}}}{\sqrt{\left. \frac{dP}{dL} \right|_{SG}}} = \frac{\sqrt{\frac{4f_{SL}}{d} \left(\frac{\rho_L v_{SL}^2}{2} \right)}}{\sqrt{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)}} \quad (1)$$

$$Y = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\left. \frac{dP}{dL} \right|_{SG}} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)} \quad (2)$$

The pressure drop per unit length equations for both the liquid phase and gas phase were derived from the combined momentum balance equation. The proposed equations to calculate the pressure drop per unit length for equilibrium stratified flow according to Taitel and Dukler (1976) are:

$$\left. \frac{dP}{dL} \right|_L = - \frac{\tau_{WL} S_L}{A_L} + \frac{\tau_I S_I}{A_L} - \rho_L g \sin(\theta) \quad (3)$$

$$\left. \frac{dP}{dl} \right|_G = - \frac{\tau_{WG} S_G}{A_G} - \frac{\tau_I S_I}{A_G} - \rho_G g \sin(\theta) \quad (4)$$

The authors suggested that either of the above equations can be used to determine the pressure drop per unit length for stratified flow in horizontal pipe.

Dukler and Hubbard (1975) developed a mathematical model to calculate the pressure drop for horizontal liquid slug flow phenomenon. This model is valid only for horizontal flow or an inclination angle of 0° . Slug flow consists of two parts: 1) the liquid slug body and 2) the film zone. This model suggests that the pressure drop per unit length for slug flow is due to two major components. The two components are: 1) the frictional pressure loss in the slug body and 2) the acceleration pressure loss in the mixing zone (Dukler and Hubbard 1975). The authors assumed homogenous no-slip flow and neglected the pressure drop in the film zone or gas pocket zone in the slug flow. Hence, Dukler and Hubbard proposed the below equation to solve the pressure drop per unit length for slug flow.

$$-\frac{dP}{dL} = -\frac{\Delta P_U}{L_U} = -\Delta P_A - \Delta P_F \quad (5)$$

where

$$-\Delta P_A = \frac{x}{A_P} (v_s - v_{LTBe}) \quad (6)$$

and

$$-\Delta P_F = \frac{2f_s \rho_s v_s^2 L_s}{d} \quad (7)$$

Hence, Dukler and Hubbard (1975) equation to find the total pressure drop per unit length for slug flow is:

$$-\frac{dP}{dL} = -\frac{\Delta P_U}{L_U} = -\frac{x}{A_P} (v_s - v_{LTBe}) - \frac{2f_s \rho_s v_s^2 L_s}{d} \quad (8)$$

Taitel and Barnea (1990) presented a mathematical model that uses the global force balance to calculate the pressure drop per unit length for slug flow condition. This model makes use of the momentum balance equation and mass balance equation over the entire slug unit length for all inclination angles. The momentum balance equation was determined for each phase (liquid and gas) in the slug unit length using Taylor bubble coordinate. The authors suggest that the liquid film profile is not constant within the film zone. It requires solving the below differential equation in an iterative manner to determine the film height along the film zone.

$$-\frac{dh_F}{dz} = \frac{\frac{\tau_f S_f}{A_f} - \frac{\tau_G S_G}{A_G} - \tau_I S_I \left(\frac{1}{A_f} + \frac{1}{A_G} \right) + (\rho_L - \rho_G)g \sin(\theta)}{\mathcal{A} + \mathcal{B} + \mathcal{C}} \quad (9)$$

$$\text{where} \quad \mathcal{A} = (\rho_L - \rho_G)g \cos(\theta) \quad (10)$$

$$\mathcal{B} = \rho_L v_F \frac{(v_{TB} - v_{LLS})H_{LLS}}{H_{LTB}^2} \frac{dH_{LTB}}{dh_f} \quad (11)$$

$$\text{and} \quad \mathcal{C} = \rho_G v_G \frac{(v_{TB} - v_{GLS})(1 - H_{LLS})}{(1 - H_{LTB})^2} \frac{dH_{LTB}}{dh_f} \quad (12)$$

The critical liquid level, h_C , located at the back of the liquid slug can be calculated by setting the denominator of the above equation to zero. The equilibrium liquid film height is obtained by setting the numerator equals to zero (Shoham 2005). Unlike Dukler and Hubbard (1975) slug flow model, Taitel and Barnea (1990) slug flow model accounts for the pressure drop in both the slug body region and the film zone. Taitel and Barnea (1990) found that the acceleration pressure drop should be excluded in the total pressure drop calculation. The authors' proposed equation to determine the pressure drop per unit length for slug is

$$-\frac{dp}{dL} = \rho_S g \sin(\theta) L_S + \frac{\tau_S \pi d}{A_p} + \rho_f g \sin(\theta) L_f + \frac{\tau_f S_f}{A_p} L_f + \frac{\tau_G S_G}{A_p} L_f \quad (13)$$

Other models such as Nicholson et al. (1978) model, Fernandes et al. (1983) model, and Sylvester (1987) simplified Model were all developed to determine pressure drop per unit length in slug flow. Unlike Taitel and Barnea (1990) model, these models neglected the pressure drop in the gas pocket zone or the film zone. In 1990, Xiao et al. combined the above models to develop a comprehensive pipeline model. The comprehensive pipeline model can be used to predict the various flow patterns, liquid holdup, and pressure drop in pipelines for all inclination angles ($-90^\circ \leq \theta \leq 90^\circ$).

CHAPTER III

EXPERIMENTAL STUDY

This chapter provides the experimental procedures, description of the test facility and techniques used in the experimental program. This chapter contains six subtopics, namely: 1) Test Facility, 2) Test Fluids, 3) Instrumentations, 4) Data Acquisition System, 5) Experimental Procedures and 6) New Horizontal Gas Anchor Description. To achieve the primary goal for this research work, a closed flow loop with horizontal well configuration was used. The horizontal flow loop was built in Room 201 (Laboratory) of the Terry Fuller Petroleum Engineering Research Building, Texas Tech University.

3.1 Test Facility

The test facility built to achieving the objective of this research is a closed flow loop with horizontal wellbore configurations. The horizontal wellbore configuration consists of the vertical, curve and lateral sections. Figure 1 shows the overall laboratory test facility for the experiments.

Figure 1: Texas Tech University two-phase horizontal well flow loop.

The test facility allows the test fluids (air and water) to flow at the same time as well as making visually analysis of each experiment. Both test fluids flowing through the test facility are discharged in a rectangular water tanks that pumps water back into the flow loop. The test facility can be subdivided into the following sections: 1) Test section, 2) Test fluids supply section, and 3) Metering section. Figure 2 shows a schematic overview of the

facility.

Figure 2: Overview of the flow loop.

3.1.1 Test Section

The test section of the facility is designed in the form of a horizontal wellbore configuration as shown in Figure 3.

Figure 3: Horizontal flow loop test section.

The vertical, curved and lateral sections of the test section are made of acrylic pipes. This allows visual understanding about the flow dynamics and patterns that exist in each section (See Figures 4 - 6). The lateral portion, which is 231.57-in long, is rested on an inclinable beam enables the experiment to be run at various inclination angles. The different angles used for the experiments are attained from a SuperwinchTM SAC1000 pulley system. The curved section has a radius of curvature of about 44 ± 1 -in. The Vertical section is about 41-in long. Three capacitance sensors (CS) are mounted along the lateral section of the flow loop. The first sensor (CS-1) is located at 33.5 ± 1 -in from the inlet, CS-2 is located at 124 ± 1 -in from the inlet and CS-3 is located at 210.75 ± 1 -in from the inlet. Three in-line pressure transmitters (PT) are mounted along the entire test section. The first pressure transmitter is mounted at 12.75 ± 1 in from the inlet, and the second is mounted at the heel just right before the tool (203 ± 1 -in from the inlet). The third pressure sensor is located at the top of the vertical portion of the test section (end of the test section).

The test facility has an outer acrylic pipe of 2.5-in Outer diameter (an inner diameter of 2.0-in) and an inner acrylic pipe with OD of 1-in (ID of 0.833-in). The outer pipe, also considered as casing, runs from the top of the vertical portion to the toe of the lateral portion. The inner pipe (also called production tubing) runs from the top of the vertical portion to the end of the curved portion. The new horizontal gas anchor is attached to the end of the production tubing at the heel of the lateral section. There are two quick closing valves (QCV) located on the tubing in the vertical section that are 17.5 ± 1 -in apart.

Figure 4: Vertical section of the flow loop. Tubing (tubing) and annulus (right) joined by a Y-shape connector.

Figure 5: Curved section of the flow loop with tubing inside casing.

Figure 6: Lateral section of the flow loop from heel to toe.

3.1.2 Test Fluid Supply Section

There are two sources that supply the test fluids to the facility. A transparent rectangular water tank provides water through the flow loop. Within the tank, there is a 5-hp PV30B Blackmer™ submersible centrifugal pump that pumps water into water line to the flow loop. The key components mounted on the water supplied line are as follows: a Coriolis flow meter, manual and automatic valves. Air is supplied to the inlet of the test section by a 1-in OD acrylic pipe. The acrylic pipe is connected to a metal pipe that is run from the dry air source's line. Mounted on the metal pipe are Coriolis flow meter, a pressure regulator, an automatic valve, and a pressure relief valve rated for 50 psig for safety purposes. Figures 7 – 8 show water and air supply sections.

Figure 7: Water supply section showing water tank and water line.

Figure 8: Dry Air supply section with pressure regulator, automatic valve (blue color) pressure relief valve, and Coriolis flow meter from left to right

3.1.3 Metering Section

The metering section consists of Coriolis flow meters, automatic control valves, capacitance sensors (CS), quick closing valves (QCV), in-line pressure transmitters (PT),

pressure relief valve, a centrifugal pump and pressure regulator. These devices enable the operator to adjust the flow system for desirable tests. Data collected from these components are obtained by a data acquisition system.

3.2 Test Fluid

The test fluids used for the experiment were air and water. Water was supplied from a transparent rectangular shaped water tank. A blue soluble dye was mixed with the water to give the water a blue coloration. Water from the storage tank is pumped through the water flow line to the test section by a submersible centrifugal pump. The pump is located in the water tank. Compressed air, assumed to be dry air, was supplied from a compressor unit. Figures 9 - 10 show the sources of the test fluids used.

Figure 9: Water source tank containing a submersible centrifugal pump.

Figure 10: Compressor unit that supply dry air to the horizontal flow loop.

Water and air physical properties were measured as well as calculated. The water and air mass flow rates were obtained by Coriolis flow meters mounted on water and air

supplied lines. The density of the dry air used in the laboratory was calculated using the ideal gas equation. The formula used is given as:

$$\rho_g = \frac{P * MW_g}{R * T} \quad (14)$$

Where P and T are the ambient pressure and temperature of the laboratory in psia and degree Rankine (R) respectively, R is the universal gas constant (psia-ft³ / lbmole/ R) and MW_g is the molecular weight of air which is 28.97 lb/lb-mole.

The air viscosity was calculated using Engineering toolbox website (Engineering Tool Box: Air viscosity). Water density was assumed at 1000 kg/m³, while its viscosity was also calculated from Engineering toolbox. Both water and air viscosities obtained from engineering toolbox were functions of the room temperature. The test fluids' properties and laboratory conditions are found in Table 1. The ambient pressure of the laboratory was calculated using air-pressure-at-altitude online calculator. Lubbock elevation (3202 ft above the sea level), obtained from the website (<https://bit.ly/2RCxDe2>), was used from the pressure calculation (<https://bit.ly/2sLmCqm>).

Table 1: Test Fluids' physical properties and laboratory condition.

Test Fluid Physical Properties/ Units	Values
Gas Density (kg/m ³)	1.0646
Gas Viscosity (Pa s) @ 73 °F	1.83E-05
Water Density (kg/m ³)	1000
Water Viscosity (Pa s) @ 73 °F	9.36E-04
Surface Tension (N/m)	0.06384
Laboratory Conditions	
Pressure (psia)	13.11
Temperature (°F)	73

3.3 Instrumentation

This subdivision covers brief information on key devices/ components installed in the facility to enable accurate and proper data collection.

3.3.1 Centrifugal Pump

A 1/3 Horsepower Honda Submersible Centrifugal Pump with 115-volt motor was placed inside the transparent rectangular water tank. This device uses its rotating impeller

to pump the water to the horizontal flow loop. The pump provides a constant flow rate. The flow rate to the flow loop is adjusted by automatic control and manual valves. The maximum flow rate provided by this pump is 40 gallons per minute. Figure 11 shows the centrifugal pump used in the laboratory.

3.3.2 Automatic Flow Control Valves

Four VA9104-GGA-2S automatic flow control valves were used throughout the facility. The first automatic control valve was installed on the water supply line, the second was installed on the air supply line, the remaining two were both installed on the casing and tubing discharged lines respectively. Both liquid and air flowing rates are controlled by the automatic valves. These valves enable the experiment to be run at different mass flow rates for water and air. The automatic flow control valves are automated by a data acquisition software system. These valves were operated from 100 percent (indicating maximum) to 30 percent (indicating minimum). The automatic control valves at air and water inlet are set to be the maximum of 50% opening when the set point in the software is 100. This is to prevent the damage to the flow loop. Figure 12 shows the automatic flow control valve.

3.3.3 Coriolis Flowmeters

A Micro-Motion™ F-Series 100S model was installed on the water flow line. A Micro-Motion™ R-Series 050S model is installed on the gas line. These two Coriolis flowmeters measure the mass flow rates of the two test fluids, water and air. The mass flow rates for water and air were used in the calculations to obtain the volumetric flow rates and superficial velocities (based on 1000 kg/m^3 for water and Eq. 14 with the pressure reading from PT2 for air). The pictures of the two Coriolis flow meters used can be seen in Figure 13 - 14.

3.3.4 Quick Closing Valves

There are two quick closing valves used in the vertical section of the flow loop. These valves are mounted on the tubing line in the vertical section. They are 45 cm apart and used to trap fluids within the trap section. The opening and closing speeds of the two

QCV are at most 0.5 second. The trap fluid in the trap section (between the two QCV) are measured to determine the volume of liquid discharged by the new gas anchor. Figure 15 shows the two QCVs installed on the production tubing in the vertical section.

3.3.5 *In-Line Pressure Transmitters*

Three Rosemount™ in-line pressure transmitters, model 3051S, were installed throughout the flow loop. The first two in-line pressure transmitters were installed at the toe (inlet) and heel of the lateral section. The last pressure transmitter was installed at the top of the tubing line in the vertical section. These in-line pressure transmitters were used to measure the pressure inside the flow loop at the three locations. These pressure transmitters have an operating range of 0 to 50 psig. For all calculations in this research work, especially gas density calculation, only pressure readings from pressure transmitter 2 (PT2), which is closed to the tool was used. Image of the in-line pressure transmitter can be seen in Figure 16.

Figure 11: Submersible Centrifugal pump.

Figure 12: Automatic Control Valve.

Figure 13: Micro-Motion Series 050S

Figure 14: Micro-motion F-Series 100S.

Figure 15: Quick closing valves on tubing.

Figure 16: Pressure Transmitter

3.4 Data Acquisition Software System

Data from each experiment are collected by data acquisition software. The software allows the operator to adjust the automatic flow control valves on the air, water, casing and tubing line to the desired measurements needed for each test. Data attained from the software system are stored as an Excel document. Mass flow rates for air and water in pound per minute (lbs/min), and pressure transmitters' readings in psig are data collected by the software system. Data collected were analyzed to establish key outcomes including pressure drop calculations and flow pattern predictions. Figure 17 shows the data acquisition software interface.

Figure 17: Data acquisition software interface.

3.5 Experimental Procedures

The experiments were done in two folds: a) with the tool in flow loop and b) without the tool in flow loop. With and without tool in flow loop experiments were done for five inclination angles. The five inclination angles are: -2° , -1° , 0° , $+1^\circ$ and $+2^\circ$. Sixteen (16) tests were performed for each of the five inclination angles. For all tests done, both casing and tubing automatic flow control valves were kept at 100 percent (maximum opening). The experimental procedures for both with and without the tool in flow loop are the same. Each test was conducted at the predetermined mass flow rate for water and air. The experimental procedure for all tests is given below in section 3.5.1.

3.5.1 Steps for Test Run

1 – Pre-inspection of all lines – operator should inspect all lines and valves used in the facility. Close valves that are not needed to be used and open only valves needed to be used for experiment. Ensure all pipes are connected properly.

2 – Use the SuperwinchTM SAC1000 pulley system to move the inclinable beam to the desire angle.

3 – Turn on the computer and log on to the data acquisition software system. Click run on the software and adjust casing, tubing, water and air automatic valves to the desire openings.

4 – Turn on the submersible centrifugal pump switch and allow the pump to run.

5 – Turn on manual compressed dry air valve to its opening position. This valve is on the compressed air line.

6 – Ensure that the desire flow rates for air and water are attained by adjusting the automatic flow control valves from the software.

7 – When the desired rates are achieved, allow the facility to run for approximately 10 minutes before collecting the data.

8 – Click the save button in the software to save the data collected by the software.

9 – Once the data is saved, turn off the pump switch first, before closing the manual valve on the compressed air line.

10 – Repeat the same process for all other tests.

3.6 New Gas Anchor Description

The new horizontal gas anchor used in the laboratory for this research work is designed with an outer pipe that enclosed an inner metal pipe as shown in Figure 18. The total length of this tool including the collar is 25.125 inches long. The collar is 2 inches long. The outer pipe has outer and inner diameters of 1-in and 0.833-in respectively. The inner pipe has outer and inner diameters of 0.63-in and 0.42-in respectively. The outer pipe and inner pipe of the new gas anchor contains 96 holes, each of which are quarter (1/4) inch size. The holes on the outer and inner pipes offset from each other in a random pattern, which creates a tortuous path. The upstream of the tool is sealed with a bull plug that breaks the waves created by the gas-liquid mixture, while the other end connects to the dip tube that is joined to the production tubing. Figure 18-a through e show the full description of the new gas anchor. This laboratory-scale tool was made to mimic the field-scale horizontal well gas anchor used in the field.

This field scale horizontal well gas anchor (proposed by Watson et al. (2018)) is shown in Figure 19. The front of the connection with a Dual Flow Connection and the back has a bull plug, as shown in Figure 20 (Watson et al. 2018). Information about the outer and inner diameter as well as field performance of the new tool can be obtained from Watson et al. 2018.

Figure 18-a through e: Laboratory Scale Model of the New Horizontal Well Gas Anchor.

Figure 19-a through c: Actual oil field model (Watson et al. 2018). A) the fully assembled horizontal gas anchor, B) the gravel pack screen used as the outer pipe of the tool, and C) the inner part of the tool.

Figure 20: Typical orientation of a new gas anchor in a horizontal well (Watson et al. 2018).

CHAPTER IV

EXPERIMENTAL RESULTS AND DISCUSSION

Several laboratory tests were conducted to quantify the performance of the new horizontal well gas anchor using water and air as the test fluids. The tests were conducted for the period of about five months. Assumptions used for the experiments are as follow:

1. Two phase flow
2. Steady state condition
3. Compressible fluid for dry air
4. Incompressible fluid for water
5. Isothermal (constant temperature)

Sixteen tests per inclination angle was conducted for the two conditions, with the tool and without the tool in the horizontal flow loop. Each test was run for approximately 8 to 10 minutes before the data were stored.

4.1 Theoretical Basis

This section provides the various theories and mathematical approaches used to analyze the results obtained from the experiments. There are four sub-divisions covered under the theoretical basis, namely: 1) Flow pattern prediction, 2) Pressure drop per unit length analysis, 3) Visual observation results and 3) Field case study.

4.1.1 *Flow Pattern Prediction*

Flow pattern prediction is a very crucial aspect of two-phase gas-liquid flow. For this research, predicting the flow pattern was done by the flowing methods. The flow pattern was determined by a visual observation. The flow pattern observations were recorded and shown in an online Youtube channel (Karmon and Panacharoensawad 2019). The visual observation was compared with the theoretical flow pattern prediction based on Taitel and Dukler (1976) model. This model is based on the combined momentum balance equation as shown below

$$X^2 \left[(\tilde{v}_L \tilde{d}_L)^{-n} \tilde{v}_L^2 \frac{\tilde{S}_L}{\tilde{A}_L} \right] - \left[(\tilde{v}_G \tilde{d}_G)^{-m} \tilde{v}_G^2 \left(\frac{\tilde{S}_G}{\tilde{A}_G} + \frac{\tilde{S}_I}{\tilde{A}_L} + \frac{\tilde{S}_I}{\tilde{A}_G} \right) \right] + 4Y = 0 \quad (15)$$

X and Y dimensionless parameters in the above equation are called Lockhart and Martinelli parameter and the inclination angle parameter, respectively. These two dimensionless quantities are used to determine the flow pattern in Taitel and Dukler (1976) model as shown in Appendix C.

4.1.2 Pressure Drop Determination

For this research, the pressure drop was only calculated for stratified smooth and stratified wavy flow regimes. All equations used to determine the pressure drop per unit length are from Taitel and Dukler (1975) mathematical model. The liquid holdup and film height were obtained by solving the combined momentum equation (Eq. 15). Then, the pressure drop per unit length was obtained from

$$\left. \frac{dP}{dL} \right|_L = - \frac{\tau_{WL} S_L}{A_L} + \frac{\tau_I S_I}{A_L} - \rho_L g \sin(\theta) \quad (16)$$

The full calculation details are given in Appendix D.

4.2 Air and Water Experiments with Tool in Flow Loop

For this set of tests, the new gas anchor was installed at the heel of the lateral section. Test fluids, water and air were mixed at the toe (inlet) of the lateral section and allow to flow toward the tool. Predetermined air and water mass flow rates were used for the tests. The total number of meaningful tests conducted for this condition is 16 tests per angle x 5 angles = 80 tests. The 16 tests per angle range from maximum gas and liquid mass flow rates to minimum gas and liquid flow rates. To achieve the maximum gas and liquid flow rates, the water and air automatic control valves were positioned at 100 percent opening. For the minimum flow rates, the automatic air and water valves were positioned at about 30 percent. The detailed test matrix for the test run with tool in flow loop is shown in tables 5 – 8. These tables also contained the calculated average superficial velocities (v_{SL} and v_{SG}), average volumetric flow rates (Q_L and Q_G) and Gas-Liquid Ratio (GLR).

4.2.1 Visual Observation Results.

The tool performance (separating and not separating) is based on visual observation mainly in the trap region of the vertical section. Video recording (Karmon and Panacharoensawad 2019) was done for each test to show the existing flow pattern in the flow loop. Stratified flow pattern was observed for the following well inclination angles (opposite to the flow inclination angle), 0° , $+1^\circ$ and $+2^\circ$. Figure 21 shows a visual image of stratified wavy (SW) for test 1, 0° inclination angle experiment. Stratified flow regime provides a good advantage for the new proposed tool. When the bull plug breaks the wave, stable flow is then created. Experimental observations revealed that when the tool is fully submerged in the liquid phase of the mixture, separation occurred.

Figure 21: Test 1 for 0° (fluid flow Horizontal). $v_{SG} = 2.499 \frac{m}{s}$; $v_{SL} = 0.0679 \frac{m}{s}$

Some operating points for horizontal flow (0°) and downward flow ($+1^\circ$ and $+2^\circ$ well) show stratified smooth (SS) flow pattern. Figure 22 shows a stratified smooth flow pattern for $+1^\circ$ well along the lateral section of the flow loop.

Figure 22: Test 7 for $+1^\circ$ (fluid flows downward). $v_{SG} = 1.680 \frac{m}{s}$; $v_{SL} = 0.0266 \frac{m}{s}$

Intermittent flow (IF mostly slug flow) was observed for Toe-down condition (-2° and -1°). For the tow down condition, the fluid mixture flows in an upward direction from the heel to the toe. The slug flow is made of two parts; namely: the slug body and the film zone or gas pocket zone. Figure 23 shows an image of the slug flow for -1° inclination angle along the lateral section.

Figure 23: Test 4 for -1° (fluid flows upward). $v_{SG} = 0.621 \frac{m}{s}$; $v_{SL} = 0.0704 \frac{m}{s}$

The trap section was mainly used to visually observe the performance of the tool. It was found that the tool separated 90 – 100% gas from the gas-liquid mixture when it was fully submerged in the liquid phase. Stratified flow pattern was another contributing factor for the tool to properly perform. Figure 24 shows the tool performance when it is fully submerged in the liquid phase of the mixture. A perfect separation of gas from the tubing was observed. The trap section in Figure 24 is between the two QCVs attached on the tubing (left). The casing (annulus space) in Figure 24 is the acrylic pipe to the right.

Figure 24: Trap section observation when the tool is fully submerged. Test 4 for +2° (fluid flows downward). $v_{SG} = 0.746 \frac{m}{s}$; $v_{SL} = 0.0641 \frac{m}{s}$

The tool could not separate gas from the mixture for the most part when intermittent flow pattern was observed. It was observed that the film zone of the slug unit had greater length than the slug body. The tool could be submerged when the tiny slug body passes it. The tool could not fully submerge for the longer film zone. This created the poorly performance of the tool. Figure 25 shows the tool performance when it is not fully submerged in the liquid phase.

Figure 25: Trap section observation when the tool is not fully submerged. Test 16 for -2° (fluid flows upward). $v_{SG} = 2.699 \frac{m}{s}$; $v_{SL} = 0.0041 \frac{m}{s}$

For the no tool condition, the new gas anchor was removed from the flow loop. The tests were performed at the same angles and mass flow rates of the test fluids used for the case where the tool was in the flow loop. A total of eighty (80) tests were conducted for this case. 16 tests per angle. The results were compared to the tests conducted when the tool was installed in the flow loop. It was observed that whenever the inlet of the tubing (without tool in flow loop) is fully covered in the liquid phase of the mixture, good separation is achieved. However, if the mixture creates wave, the tubing is unable to break the wave and create a more stable flow as in the case of the tool being used in the experiment. This aspect shows the disadvantage of using the bare tubing and the advantage of using the new gas anchor in a horizontal well.

4.2.2 *Superficial velocity analysis on the tool separation performance*

The criterion for the new horizontal well gas anchor to separate or not separate gas from the mixture squarely depends on the submergibility of the tool in the liquid phase. The superficial velocity of the gas phase has a great influence on the tool performance. It was found that there is a critical superficial gas velocity (v_{SG}), above which the new horizontal well gas anchor could not separate. The critical v_{SG} found is approximately 1.4 m/s. Below this critical v_{SG} , the tool separated 90 – 100% gas from the mixture. Table 2 in

sec. 4.2.3 provides a column that show the tool performance analysis. In the rightmost column of Table 2, green and red backgrounds represent the cases where the tool can do 90%+ separation (work) and cannot do the separation (does not work), respectively. The visual observations for other angles are given in Table 5 – 8 located in Appendix B. The same behavior of the tool performance was observed. The tool was found to work (90%+ separation) in other angle cases when it was fully submerged in the liquid phase.

4.2.3 Positive One (1°) Degree: Toe-Up Condition – Tool in Flow Loop

It should be noted that positive one degree, toe up condition, applies only to the inclination angle with respect to the lateral section. The heel of the lateral section was the reference point. However, the fluid flows negative one degree (-1°) from toe to heel of the lateral section for this toe up condition. Table 2 shows the test matrix and the observed tool performance for $+1^\circ$ (Toe-up condition).

Table 2: Operating condition for $+1^\circ$ (Toe-up) with tool in flow loop (Test Matrix).

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m ³ /sec)	Liquid Vol. Flow (m ³ /sec)	VsG (m/s)	VsL (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.56E-02	3.28E-01	5.78E-03	1.49E-04	2.85	7.35E-02	190	SW
test 2	9.96E-03	2.92E-01	3.55E-03	1.32E-04	1.75	6.54E-02	131	SW
test 3	6.98E-03	3.09E-01	2.50E-03	1.40E-04	1.24	6.91E-02	88	SW
test 4	4.34E-03	3.06E-01	1.58E-03	1.39E-04	0.78	6.84E-02	56	SW
test 5	4.24E-03	1.19E-01	1.60E-03	5.41E-05	0.79	2.67E-02	145	SW
test 6	6.67E-03	1.23E-01	2.52E-03	5.56E-05	1.25	2.74E-02	223	SW
test 7	1.00E-02	1.21E-01	3.78E-03	5.47E-05	1.86	2.70E-02	340	SW
test 8	1.55E-02	1.26E-01	6.01E-03	5.70E-05	2.96	2.81E-02	516	SW
test 9	1.55E-02	4.34E-02	6.10E-03	1.97E-05	3.01	9.72E-03	1528	SW
test 10	1.04E-02	4.13E-02	4.03E-03	1.87E-05	1.99	9.23E-03	1056	SW
test 11	6.78E-03	4.16E-02	2.62E-03	1.89E-05	1.29	9.32E-03	680	SW
test 12	4.54E-03	4.14E-02	1.73E-03	1.88E-05	0.85	9.26E-03	451	SW
test 13	4.50E-03	2.07E-02	1.72E-03	9.41E-06	0.85	4.64E-03	897	SW
test 14	7.03E-03	2.05E-02	2.72E-03	9.31E-06	1.34	4.59E-03	1435	SW
test 15	1.00E-02	2.13E-02	3.91E-03	9.67E-06	1.93	4.77E-03	1947	SW
test 16	1.54E-02	2.29E-02	6.12E-03	1.04E-05	3.02	5.13E-03	2886	SW

The readings in the Table 2 are average values for each parameter. The mass flow rate readings were obtained from the Coriolis Flowmeter. The Volumetric flow rates,

superficial velocities and gas-liquid ratio values for each test in the table were computed using the following equations.

$$Q_G = \frac{W_G}{\rho_G}, \quad Q_L = \frac{W_L}{\rho_L}, \quad v_{SL} = \frac{Q_L}{A_P}, \quad v_{SG} = \frac{Q_G}{A_P}, \quad GLR = \frac{Q_G}{Q_L} \quad (17)$$

4.2.4 Positive One (1°) Degree: Toe-Up Condition Flow Pattern Predictions

The flow pattern was determined by 1) Taitel and Dukler (1976) flow pattern model and 2) Shoham (2005) FLOPATN program based on Barnea (1986) model. The manual calculation based on Taitel and Dukler (1976) is similar to the FLOPATN's results. Yet, they are not identical because these two methods are based on different models. Figure 26 shows the flow pattern predictions of each operating point using Shoham (2005) software.

Figure 26: Flow Pattern Map Predication (+1° Toe-Up). Fluid Flows downward (-1°).

It can be seen in Figure 26 that stratified flow regime is the only flow pattern that existed. Stratified Wavy dominated stratified smooth for the most part. The new gas anchor separated gas from gas-liquid mixture for eight operating points displayed in green color. These values fall below the critical gas superficial velocity (v_{SG}). Operating points in red color, as seen in Figure 267, were found to be above the critical v_{SG} , indicating that the tool could not separate gas from the gas-liquid mixture.

4.2.5 Positive Two (+2°) Degree: Toe-Up Condition – Tool in Flow Loop

In Figure 27, all operating points for the given v_{SL} and v_{SG} values calculated fall within the Stratified Wavy region. Operating points in red color indicate the condition at which the new gas anchor did not work, while operating points in green color indicate the condition at which the tool work. Test matrix for +2° (Toe-Up) is found in Table 5 in the Appendix B.

Figure 27: Flow Pattern Map Predication (+2° Toe-Up). Fluid Flows downward (-2 °).

4.2.6 Zero (0°) Degree: Toe-Flat Condition (Horizontal) – Tool in Flow Loop

Operating points in Figure 28 fall mainly within the stratified smooth region. The New Gas Anchor was observed to separate gas from the gas-liquid mixture for all gas superficial velocities (v_{SG}) below the critical v_{SG} (1.4 m/s). Test matrix for 0° (Toe-Flat meaning horizontal) is found in Table 6 in the Appendix B

Figure 28: Flow Pattern Map Predication – (0° Toe-Flat). Fluid Flows horizontally.

4.2.7 Negative One & Two Degree: Toe-Down Condition-Tool in Flow Loop

Figures 29 – 30 show the flow pattern map for Toe-Down Condition. It can be seen from these figures that intermittent (Slug flow) flow is the dominant flow pattern. The videos for tests conducted at -2° and -1° visually confirmed the existence of intermittent flow. Test matrices for -2° and -1° (Toe-Down Condition) are found in tables 7 and 8 respectively in the Appendix B.

Figure 29: Flow Pattern Map Predication (-1° Toe-Down). Fluid Flows Upward ($+1^\circ$).

Figure 30: Flow Pattern Map Predication (-2° Toe-Down). Fluid Flows Upward ($+2^\circ$).

4.3 Air and Water Experiments without Tool in Flow Loop

Figure 31 shows the flow pattern map for $+1^\circ$ (Toe-up condition) without the tool in flow loop. It is observed in Figure 26 that stratified wavy dominates stratified smooth, as almost all operating points fall within the stratified wavy region. Figures 33 - 36 show the results obtained for the five inclination angles' ($+2^\circ$, 0° , -2° and -1°) experiments respectively for the case with no tool in flow loop. Test matrices are found in Tables 9 through 13.

Figure 31: Flow Pattern Map Prediction ($+1^\circ$ Toe-Up) without tool in flow loop.

4.4 Field Prediction Study

This section relates the performance of the tool to field condition. The total of fifteen field case studies were performed; three studies for each angle ($+2^\circ$, $+1^\circ$, 0° , -1° and -2°). Critical parameters used in calculations are found in

Table 3. We can predict the performance of the working of the tool in the field based on the liquid height. Calculations were done to determine the equivalent v_{SL} and v_{SG} of the laboratory condition to the field condition. The corresponding laboratory v_{SL} and v_{SG} values in each case were obtained by matching the Lockhart and Martinelli parameter, X , and inclination parameter, Y , for the field condition and laboratory condition. In other words, $X_{Lab} = X_{Field}$ and $Y_{Lab} = Y_{Field}$. Furthermore, extrapolations to field case were done to understand if the tool may work or not on the field. The ratio of the field casing ID, 4.8-in, to the field tool OD, 2.375-in is 2.02, which is a direct scaling from the laboratory case where the Lab casing ID is 2-in and lab-tool OD is 1-in (2/1 ratio).

The hypothesis of this experiment is that if the new horizontal well gas anchor is fully submerged, then it works. The equivalent lab condition confirms that hypothesis. When we match X and Y , for the field and laboratory conditions, we expect to have $\tilde{h}_{L,field} = \tilde{h}_{L,lab}$, because $\tilde{h}$ is only a function of X and Y , theoretically. The submergence of the tool for both field and laboratory cases should also be the same when $\tilde{h}$ of the liquid phase are the same, because the tool-to-casing ratio in both field and laboratory cases are approximately the same $\left(\tilde{h}_{tool,field} = \frac{OD_{tool}}{ID_{casing}} = 2.02 \right) \cong \left(\tilde{h}_{tool,lab} = \frac{OD_{tool}}{ID_{casing}} = 2.0 \right)$. Applying this dimensionless liquid level, $\tilde{h}_L$, concept, to the three cases, it can be deduced that when the tool is not fully submerged in the field case, it won't be fully submerged in the lab case. Pressure drop per unit length comparison for the three field prediction cases were done for $+2^\circ$, $+1^\circ$ and 0° . The calculated pressure drop per unit length values obtained for the field condition did not match with the laboratory condition for each case due to the several factors including fluid densities and viscosities. Results from the three cases per angle are found in tables 14 through 17. The step by step procedure for matching laboratory conditions to field condition can be found in Appendix D.

Table 3: Major parameters used in the field case study.

Laboratory condition		Field condition	
Casing ID [in]	2	Casing ID [in]	4.8
Tubing OD [in]	1	Tubing OD [in]	2.0
Absolute Roughness [μm]	0	Absolute Roughness [μm]	0
Angle [$^{\circ}$]	+2, +1, 0, -1, -2		
Gas Anchor		Gas Anchor	
- Outer Pipe OD [in]	1	- Outer Pipe OD [in]	2
- Outer Pipe ID [in]	0.83	- Outer Pipe ID [in]	1.875
- Inner Pipe OD [in]	0.63	- Inner Pipe OD [in]	1.5
- Inner Pipe ID [in]	0.42	- Inner Pipe ID [in]	1
Fluids:		Fluids:	
✓ Gas density [kg/m^3]	1.0646	- Gas density [kg/m^3]	64.98
✓ Gas viscosity [$\text{Pa}\cdot\text{s}$]	1.83E-05	- Gas viscosity [$\text{Pa}\cdot\text{s}$]	1.183E-05
✓ Oil density [kg/m^3]	1000	- Oil density [kg/m^3]	850
✓ Oil viscosity [$\text{Pa}\cdot\text{s}$]	9.36E-04	- Oil viscosity [$\text{Pa}\cdot\text{s}$]	0.003
✓ Surface Tension [N/m]	0.0638	- Surface Tension [N/m]	0.0638
Characteristics		Characteristics	
- Pressure [psia]	13.11	- Pressure [psia]	1000
- Temperature [$^{\circ}\text{F}$]	73 $^{\circ}\text{F}$	- Temperature [$^{\circ}\text{F}$]	106

4.4.1 Field Prediction: +1 $^{\circ}$ (Toe-Up Condition) with tool in flow loop

The three sensitivity cases were conducted for +1 $^{\circ}$ (Toe-up). Data used in the calculation for case one (1) were obtained from Watson et al. (2018). The Gas-Liquid Ratio (GLR) for case 1 was 26.7 SCF/STB. The calculated v_{SL} and v_{SG} values for the field condition are 4.25×10^{-3} m/s and 5.61×10^{-2} m/s, respectively. After matching the Lockhart and Martinelli parameter, X , and inclination parameter, Y , for case one, the corresponding laboratory v_{SL} and v_{SG} values are 3.23×10^{-2} m/s and 8.77×10^{-4} m/s, respectively. Data used for case 2 and 3 were assumed. The matching of the Lockhart and Martinelli parameter, X , and inclination parameter, Y , were performed to obtain the corresponding laboratory v_{SL} and v_{SG} values.

Table 4 shows the field v_{SL} and v_{SG} values and the equivalent laboratory v_{SL} and v_{SG} values for $+1^\circ$ (Toe up condition) with tool in flow loop. The corresponding v_{SL} and v_{SG} values for the three cases were plotted in the flow pattern map for $+1^\circ$ (See Figure 32).

Operating points for case 1 and 2, as shown in Figure 32, clearly fall within the region that the tool is fully submerged and could potentially separate gas from mixture in the field. The operating point for case 3, as shown in Figure 32, falls in the area above the critical v_{SG} value. This indicates that the tool was not fully submerged and could not separate gas from the gas-liquid mixture in the field. Moreover, we found that for case 1 and 2, the liquid height was higher than the tool height. This suggest that the tool will separate the gas from the mixture. However, for case 3, the height of the liquid was less than the tool height; suggesting poor performance of the tool. The calculation from our prediction model is in consistent with the effects of the superficial gas velocity on the tool performance. All excel files with the calculations relating to the three sensitivity cases are provided via the Cloud Storage (Karmon and Panacharoensawad 2019). The prediction for case 1 shows that the new gas anchor could potentially separate gas from the mixture. This is consistent with the finding in Watson et al. (2018) that the tool increased the well productivity. Figures 37 - 40 show the operating points for the three field case studies performed for the condition with tool in flow loop. These figures show the condition that the tool should and should not work. Moreover, Tables 14 through 17 show the field v_{SL} and v_{SG} values and the equivalent laboratory v_{SL} and v_{SG} values for $+2^\circ$, 0° , -1° , and -2° respectively with tool in flow loop. This proposed tool performance prediction is based on the submergibility of the tool. It shows the consistency prediction for the laboratory cases. Nevertheless, the actual field data are needed to fully validate this proposed method.

Table 4: Field Case Study (+1° Toe-up condition) with tool in flow loop.

Field Case Parameters					
Case 1		Field Condition (Calculated)		Equivalent Condition	Laboratory
Oil flow rate [STBO/day]	15	v_SL [m/s] =	5.61E-02	v_SL [m/s] =	3.50E-02
Water flow rate [STBW/day]	341	v_SG [m/s] =	4.25E-03	v_SG [m/s] =	8.58E-04
Gas flow rate [SCFD]	9500	dp/dL_G [Pa/m]	-1.11E+01	dp/dL_G [Pa/m]	-1.82E-01
GLR [SCF/STBL]	26.7	X = 45.7			
		Y = -8.79E+5			
Case 2		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	2.24E-01	v_SG [m/s] =	8.46E-01
Gas flow rate [SCFD]	5.00E+04	dp/dL_G [Pa/m]	-1.08E+01	dp/dL_G [Pa/m]	2.08E-01
Gas flow rate [SCFD]	1000	X = 1.90			
		Y = -5.93E+02			
Case 3		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	4.48E-01	v_SG [m/s] =	1.69E+00
Gas flow rate [SCFD]	1.00E+06	dp/dL_G [Pa/m]	-1.01E+01	dp/dL_G [Pa/m]	1.18E+00
GLR [SCF/STBL]	2000	X = 1.02			
		Y = -1.70E+02

Figure 32: Field Case Study Flow Pattern Map Predication (+1° Toe-Up) with tool in flow loop.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

Downhole gas separation from gas-liquid mixture can be achieved by using a downhole gas separator/ anchor. Free gas produced from liquid phase as reservoir pressure drops below bubble point pressure poses a severe treat to some artificial lift systems especially sucker rod pumps. The adverse effects ranging from reduction in pump performance to well pump off condition. Experimental study has been conducted on a new horizontal well gas anchor. The objective of the experiment is to investigate the separation performance of the new gas anchor. The performance of a downhole separator/ anchor can be affected by downhole gas-liquid ratios. Experiments were conducted using water and gas as test fluids and inclination angles including $+2^\circ$, $+1^\circ$, 0° , -1° , and -2° . The tests were conducted for tool in flow loop and without tool in flow loop condition.

The new gas anchor could potentially separate gas from the gas-liquid mixture provided that the inner pipe of the tool is fully submerged in the liquid phase. For the no tool experiments, separation occurs when the entrance of the tubing is below the liquid phase of the mixture. However, with the tool in flow loop condition has greater advantage over the condition without the tool in flow loop. The bull plug of the new tool was observed to create a more stable flow by breaking the wave created by the mixture. Moreover, the tool creates a tortuous path for the dissolved gas in oil to separate out. The impact of the tortuous path on removing the dissolved gas was not studied in this experimental program, because the facility is a low-pressure facility. The wave breaking, and impact of the tortuous path ensure better gas separation from the mixture as compare to the no-tool condition. From the results, a critical gas superficial velocity of approximately 1.4 m/s was established. The new tool could separate gas for a v_{SG} value below the critical v_{SG} and could not separate gas from mixture for v_{SG} values higher than the critical v_{SG} . Above the critical v_{SG} , the tool could not be fully submerged.

Fifteen field case studies were conducted to test the hypothesis that the tool needs to be fully submerged to work properly. The operating points where the tool was and was not fully submerged in the field case were selected. The Lockhart and Martinelli parameter, X , and inclination-angle parameter, Y , were used to determine the equivalent v_{SL} and v_{SG} for the laboratory conditions. The comparison of the equivalent superficial velocities and available experimental data showed that the fully submerge hypothesis agreed with the data. In addition, these field case studies also serve as the way to determine if the tool should work properly in the field condition, or not.

5.2 Recommendations

The recommendations for the future studies are as follows:

1. The tool performance in the field case was predicted, based on the fully submerged hypothesis. This hypothesis should be tested against the data from a larger flow loop, so that it can be fully investigated.
2. This testing program cannot test the impact of the tool tortuous path on separating the dissolved gas out from oil phase. This is because the facility is a low-pressure facility. There was no significant amount of air dissolved in water phase that can liberate by moving through the tortuous path. If this test is conducted in a high-pressure facility, then it is not possible to observe the impact of the tortuous path on removing gas bubble, visually. Nevertheless, it is possible to visually observe if the tool is fully submerged or not in the high-pressure case by using a sapphire window. Then, the case with and without the tool can be tested. In addition, the tool with different degree of tortuosity can also be tested.
3. The downward return line from the test section to the tank created a suction effect of the liquid moving downward artificially sucking gas into the gas anchor. This downward section should be modified by adding a free-flashing chamber at the top of the flow loop. This will allow the gas-liquid two-phase flow to experience the atmospheric pressure at the top of the well without feeling the suction that created in the return line.

4. Using the quick closing valves during experiments created a shut-down of the data acquisition system. There is a need to correct this fault.
5. That the tubing and casing lines discharged in two separate vessels (or add the Coriolis flow meter on the return lines). This will enable laboratory operators to quantitatively evaluate the performance of the new gas anchor.

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APPENDIX A

The below flow pattern maps are for the condition where the gas anchor was removed from the flow loop.

Figure 33: Flow Pattern Map Predication (+2° Toe-Up) without tool in flow loop.

Figure 34: Flow Pattern Map Predication (0° Horizontal flow) without tool in flow loop.

Figure 35: Flow Pattern Map Predication (-2° Toe-Down) without tool in flow loop.

Figure 36: Flow Pattern Map Predication (-1° Toe-Down) without tool in flow loop.

Figure 37: Field Case Study Flow Pattern Map Predication (+2° Toe-Up) with tool in flow loop.

Figure 38: Field Case Study Flow Pattern Map Predication (0° Horizontal flow) with tool in flow loop.

Figure 39: Field Case Study Flow Pattern Map Predication (-1° Toe-Down) with tool in flow loop.

Figure 40: Field Case Study Flow Pattern Map Predication (-2° Toe-Down) with tool in flow loop.

APPENDIX B

Table 5: +2° (Toe up condition) With tool in flow loop. Test matrix

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	V_{SG} (m/s)	V_{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.56E-02	3.14E-01	5.76E-03	1.42E-04	2.84	7.02E-02	198	SW
test 2	1.02E-02	3.18E-01	3.78E-03	1.44E-04	1.87	7.12E-02	128	SW
test 3	6.70E-03	3.23E-01	2.51E-03	1.47E-04	1.24	7.23E-02	84	SW
test 4	4.46E-03	2.99E-01	1.62E-03	1.36E-04	0.80	6.69E-02	59	SW
test 5	4.56E-03	1.19E-01	1.71E-03	5.41E-05	0.84	2.67E-02	155	SW
test 6	7.05E-03	1.18E-01	2.64E-03	5.33E-05	1.30	2.63E-02	242	SW
test 7	9.89E-03	1.23E-01	3.83E-03	5.57E-05	1.89	2.75E-02	337	SW
test 8	1.55E-02	1.23E-01	5.99E-03	5.56E-05	2.96	2.74E-02	529	SW
test 9	1.55E-02	4.38E-02	6.13E-03	1.99E-05	3.02	9.79E-03	1514	SW
test 10	9.93E-03	4.30E-02	3.92E-03	1.95E-05	1.93	9.63E-03	985	SS
test 11	6.73E-03	4.10E-02	2.57E-03	1.86E-05	1.27	9.18E-03	677	SS
test 12	4.57E-03	4.24E-02	1.74E-03	1.92E-05	0.86	9.49E-03	445	SS
test 13	4.41E-03	1.99E-02	1.70E-03	9.05E-06	0.84	4.46E-03	921	SS
test 14	6.75E-03	1.96E-02	2.62E-03	8.89E-06	1.29	4.39E-03	1443	SS
test 15	1.01E-02	2.06E-02	4.00E-03	9.36E-06	1.97	4.62E-03	2096	SS
test 16	1.55E-02	2.04E-02	6.16E-03	9.23E-06	3.04	4.55E-03	3272	SS

Table 6: 0° (Horizontal flow) with tool in flow loop. Test Matrix

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	V_{SG} (m/s)	V_{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.55E-02	3.35E-01	5.75E-03	1.52E-04	2.84	7.49E-02	186	SW
test 2	9.90E-03	3.36E-01	3.72E-03	1.52E-04	1.84	7.51E-02	120	SW
test 3	6.65E-03	3.28E-01	2.45E-03	1.49E-04	1.21	7.33E-02	81	SW
test 4	4.53E-03	3.09E-01	1.66E-03	1.40E-04	0.82	6.92E-02	58	SW
test 5	4.29E-03	1.24E-01	1.61E-03	5.59E-05	0.79	2.76E-02	142	SW
test 6	6.63E-03	1.24E-01	2.27E-03	5.62E-05	1.12	2.77E-02	198	SW
test 7	1.03E-02	1.24E-01	3.92E-03	5.62E-05	1.93	2.77E-02	342	SW
test 8	1.55E-02	1.18E-01	6.02E-03	5.34E-05	2.97	2.64E-02	553	SW
test 9	1.55E-02	4.57E-02	6.13E-03	2.07E-05	3.02	1.02E-02	1448	SW
test 10	9.83E-03	4.59E-02	3.81E-03	2.08E-05	1.88	1.03E-02	898	SW
test 11	6.69E-03	4.47E-02	2.57E-03	2.03E-05	1.27	1.00E-02	622	SW
test 12	4.24E-03	4.85E-02	1.62E-03	2.20E-05	0.80	1.09E-02	361	SS
test 13	4.28E-03	1.88E-02	1.64E-03	8.53E-06	0.81	4.21E-03	945	SS
test 14	6.68E-03	1.57E-02	2.59E-03	7.13E-06	1.28	3.52E-03	1780	SW
test 15	9.85E-03	1.90E-02	3.83E-03	8.61E-06	1.89	4.25E-03	2179	SW
test 16	1.54E-02	1.90E-02	6.13E-03	8.61E-06	3.03	4.25E-03	3490	SW

Table 7: -1° (Toe down condition) with tool in flow loop. Test Matrix

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m ³ /sec)	Liquid Vol. Flow (m ³ /sec)	V _{SG} (m/s)	V _{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.55E-02	3.17E-01	5.56E-03	1.44E-04	2.74	7.09E-02	190	IF (Slug)
test 2	9.69E-03	3.18E-01	3.58E-03	1.44E-04	1.77	7.12E-02	122	IF (Slug)
test 3	5.79E-03	3.23E-01	2.15E-03	1.46E-04	1.06	7.22E-02	72	IF (Slug)
test 4	3.63E-03	3.29E-01	1.36E-03	1.49E-04	0.67	7.37E-02	45	IF (Slug)
test 5	4.14E-03	1.23E-01	1.57E-03	5.57E-05	0.77	2.75E-02	138	IF (Slug)
test 6	5.81E-03	1.26E-01	2.25E-03	5.71E-05	1.11	2.82E-02	193	IF (Slug)
test 7	9.77E-03	1.24E-01	3.75E-03	5.61E-05	1.85	2.77E-02	328	IF (Slug)
test 8	1.55E-02	1.24E-01	5.99E-03	5.64E-05	2.96	2.78E-02	520	IF (Slug)
test 9	1.55E-02	4.16E-02	5.86E-03	1.89E-05	2.89	9.32E-03	1521	IF (Slug)
test 10	9.72E-03	5.05E-02	3.76E-03	2.29E-05	1.86	1.13E-02	805	IF (Slug)
test 11	5.91E-03	4.72E-02	2.31E-03	2.14E-05	1.14	1.06E-02	529	IF (Slug)
test 12	4.11E-03	4.56E-02	1.60E-03	2.07E-05	0.79	1.02E-02	379	IF (Slug)
test 13	4.28E-03	1.68E-02	1.64E-03	7.63E-06	0.81	3.76E-03	1057	IF (Slug)
test 14	6.01E-03	1.80E-02	2.35E-03	8.18E-06	1.16	4.04E-03	1411	IF (Slug)
test 15	9.74E-03	1.78E-02	3.87E-03	8.06E-06	1.91	3.98E-03	2354	IF (Slug)
test 16	1.55E-02	1.71E-02	6.36E-03	7.78E-06	3.14	3.84E-03	4012	IF (Slug)

Table 8: -2° (Toe down condition) with tool in flow loop. Test Matrix

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m ³ /sec)	Liquid Vol. Flow (m ³ /sec)	V _{sG} (m/s)	V _{sL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.55E-02	3.07E-01	5.48E-03	1.39E-04	2.70	6.87E-02	193	IF (Slug)
test 2	8.29E-03	3.24E-01	3.03E-03	1.47E-04	1.50	7.25E-02	101	IF (Slug)
test 3	4.10E-03	3.19E-01	1.53E-03	1.45E-04	0.76	7.14E-02	52	IF (Slug)
test 4	1.59E-03	3.24E-01	5.89E-04	1.47E-04	0.29	7.25E-02	20	IF (Slug)
test 5	1.59E-03	1.26E-01	5.97E-04	5.70E-05	0.29	2.81E-02	51	IF (Slug)
test 6	4.27E-03	1.27E-01	1.64E-03	5.77E-05	0.81	2.85E-02	139	IF (Slug)
test 7	7.98E-03	1.26E-01	3.07E-03	5.72E-05	1.51	2.82E-02	263	IF (Slug)
test 8	1.55E-02	1.26E-01	5.97E-03	5.73E-05	2.94	2.83E-02	511	IF (Slug)
test 9	1.55E-02	4.44E-02	6.08E-03	2.02E-05	3.00	9.94E-03	1479	IF (Slug)
test 10	8.17E-03	4.40E-02	3.24E-03	2.00E-05	1.60	9.86E-03	796	IF (Slug)
test 11	3.85E-03	4.29E-02	1.48E-03	1.95E-05	0.73	9.60E-03	374	IF (Slug)
test 12	1.60E-03	3.93E-02	6.05E-04	1.78E-05	0.30	8.81E-03	166	IF (Slug)
test 13	2.24E-03	1.57E-02	8.57E-04	7.12E-06	0.42	3.51E-03	590	IF (Slug)
test 14	3.90E-03	1.66E-02	1.51E-03	7.53E-06	0.75	3.72E-03	983	IF (Slug)
test 15	8.23E-03	1.59E-02	3.23E-03	7.22E-06	1.59	3.56E-03	2195	IF (Slug)
test 16	1.56E-02	1.65E-02	6.18E-03	7.51E-06	3.05	3.70E-03	4040	IF (Slug)

Table 9: +1° (Toe up condition) without tool in flow loop.

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	VsG (m/s)	VsL (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.52E-02	3.20E-01	5.78E-03	1.45E-04	2.85	7.17E-02	195	SW
test 2	1.01E-02	3.21E-01	3.84E-03	1.45E-04	1.89	7.17E-02	129	SW
test 3	6.49E-03	3.11E-01	2.37E-03	1.41E-04	1.17	6.95E-02	83	SW
test 4	4.42E-03	3.13E-01	1.61E-03	1.42E-04	0.79	6.99E-02	56	SW
test 5	4.35E-03	1.11E-01	1.63E-03	5.04E-05	0.81	2.48E-02	159	SW
test 6	6.55E-03	1.22E-01	2.47E-03	5.54E-05	1.22	2.73E-02	219	SW
test 7	9.90E-03	1.26E-01	3.87E-03	5.73E-05	1.91	2.83E-02	331	SW
test 8	1.24E-02	1.27E-01	4.87E-03	5.75E-05	2.40	2.84E-02	416	SW
test 9	1.52E-02	4.25E-02	6.03E-03	1.93E-05	2.97	9.50E-03	1535	SW
test 10	9.79E-03	4.03E-02	3.82E-03	1.83E-05	1.88	9.01E-03	1025	SW
test 11	6.61E-03	4.02E-02	2.55E-03	1.82E-05	1.26	8.99E-03	686	SW
test 12	4.22E-03	4.04E-02	1.62E-03	1.83E-05	0.80	9.04E-03	433	SW
test 13	4.22E-03	1.72E-02	1.62E-03	7.81E-06	0.80	3.85E-03	1019	SW
test 14	5.54E-03	1.87E-02	2.17E-03	8.50E-06	1.07	4.20E-03	1249	SW
test 15	9.90E-03	1.85E-02	3.87E-03	8.39E-06	1.91	4.14E-03	2262	SW
test 16	1.51E-02	1.86E-02	6.10E-03	8.42E-06	3.01	4.15E-03	3554	SW

Table 10: +2° (Toe up condition) without tool in flow loop.

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	V_{SG} (m/s)	V_{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.52E-02	3.18E-01	5.75E-03	1.44E-04	2.84	7.11E-02	196	SW
test 2	1.01E-02	3.21E-01	3.84E-03	1.45E-04	1.89	7.17E-02	129	SW
test 3	6.76E-03	2.99E-01	2.47E-03	1.36E-04	1.22	6.69E-02	89	SW
test 4	4.37E-03	3.08E-01	1.59E-03	1.39E-04	0.78	6.88E-02	56	SW
test 5	4.35E-03	1.24E-01	1.65E-03	5.64E-05	0.81	2.78E-02	143	SW
test 6	6.86E-03	1.17E-01	2.61E-03	5.29E-05	1.29	2.61E-02	242	SW
test 7	1.02E-02	1.21E-01	3.97E-03	5.50E-05	1.96	2.71E-02	354	SW
test 8	1.52E-02	1.19E-01	5.92E-03	5.38E-05	2.92	2.66E-02	539	SW
test 9	1.52E-02	4.66E-02	6.04E-03	2.11E-05	2.98	1.04E-02	1401	SW
test 10	1.02E-02	4.60E-02	4.01E-03	2.09E-05	1.98	1.03E-02	943	SW
test 11	6.97E-03	4.42E-02	2.69E-03	2.00E-05	1.33	9.89E-03	658	SS
test 12	4.42E-03	4.36E-02	1.68E-03	1.98E-05	0.83	9.76E-03	416	SS
test 13	4.18E-03	1.63E-02	1.61E-03	7.42E-06	0.79	3.66E-03	1063	SS
test 14	6.56E-03	1.58E-02	2.53E-03	7.18E-06	1.25	3.54E-03	1731	SS
test 15	1.02E-02	1.63E-02	4.06E-03	7.39E-06	2.00	3.65E-03	2694	SS
test 16	1.52E-02	1.40E-02	6.08E-03	6.35E-06	3.00	3.13E-03	4695	SS

Table 11: 0° (Horizontal Flow) without tool in flow loop.

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	VsG (m/s)	VsL (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.53E-02	3.28E-01	5.72E-03	1.49E-04	2.82	7.34E-02	187	SW
test 2	9.93E-03	3.32E-01	3.74E-03	1.51E-04	1.84	7.43E-02	122	SW
test 3	7.02E-03	3.14E-01	2.54E-03	1.42E-04	1.25	7.02E-02	88	SW
test 4	4.20E-03	3.18E-01	1.53E-03	1.44E-04	0.76	7.13E-02	52	SW
test 5	4.36E-03	1.14E-01	1.66E-03	5.16E-05	0.82	2.54E-02	158	SW
test 6	6.57E-03	1.13E-01	2.48E-03	5.11E-05	1.19	2.52E-02	238	SW
test 7	9.89E-03	1.15E-01	3.71E-03	5.21E-05	1.83	2.57E-02	349	SW
test 8	1.52E-02	1.19E-01	5.92E-03	5.40E-05	2.92	2.66E-02	538	SW
test 9	1.53E-02	4.56E-02	6.06E-03	2.07E-05	2.99	1.02E-02	1437	SW
test 10	8.84E-03	4.56E-02	3.46E-03	2.07E-05	1.71	1.02E-02	820	SW
test 11	6.76E-03	4.53E-02	2.61E-03	2.05E-05	1.29	1.01E-02	624	SW
test 12	4.40E-03	4.47E-02	1.69E-03	2.03E-05	0.83	1.00E-02	408	SS
test 13	4.32E-03	2.18E-02	1.67E-03	9.89E-06	0.82	4.88E-03	827	SS
test 14	6.68E-03	2.11E-02	2.59E-03	9.55E-06	1.28	4.71E-03	1329	SW
test 15	1.00E-02	2.24E-02	3.90E-03	1.02E-05	1.92	5.02E-03	1881	SW
test 16	1.27E-02	2.22E-02	5.16E-03	1.01E-05	2.55	4.97E-03	2512	SW

Table 12: -1° (Toe down condition) without tool in flow loop.

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	V_{SG} (m/s)	V_{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.52E-02	3.43E-01	6.01E-03	1.56E-04	2.97	7.69E-02	189	IF (Slug)
test 2	9.90E-03	3.39E-01	3.83E-03	1.54E-04	1.89	7.59E-02	122	IF (Slug)
test 3	5.92E-03	3.22E-01	2.24E-03	1.46E-04	1.10	7.22E-02	75	IF (Slug)
test 4	4.29E-03	3.35E-01	1.69E-03	1.52E-04	0.83	7.49E-02	52	IF (Slug)
test 5	3.77E-03	1.23E-01	1.45E-03	5.58E-05	0.72	2.76E-02	127	IF (Slug)
test 6	5.99E-03	1.25E-01	2.40E-03	5.67E-05	1.18	2.80E-02	207	IF (Slug)
test 7	9.25E-03	1.25E-01	3.72E-03	5.68E-05	1.83	2.80E-02	321	IF (Slug)
test 8	1.51E-02	1.22E-01	5.66E-03	5.53E-05	2.79	2.73E-02	502	IF (Slug)
test 9	1.51E-02	4.56E-02	5.94E-03	2.07E-05	2.93	1.02E-02	1408	IF (Slug)
test 10	9.53E-03	4.66E-02	3.87E-03	2.11E-05	1.91	1.04E-02	898	IF (Slug)
test 11	6.00E-03	4.58E-02	2.30E-03	2.08E-05	1.14	1.03E-02	543	IF (Slug)
test 12	3.73E-03	4.50E-02	1.43E-03	2.04E-05	0.70	1.01E-02	342	IF (Slug)
test 13	3.76E-03	1.85E-02	1.45E-03	8.38E-06	0.72	4.13E-03	850	IF (Slug)
test 14	6.01E-03	1.97E-02	2.35E-03	8.95E-06	1.16	4.41E-03	1289	IF (Slug)
test 15	9.49E-03	1.76E-02	3.63E-03	7.97E-06	1.79	3.93E-03	2233	IF (Slug)
test 16	1.52E-02	1.97E-02	6.15E-03	8.95E-06	3.03	4.42E-03	3366	IF (Slug)

Table 13: -2° (Toe down condition) without tool in flow loop.

	Air Mass Flow (lb/sec)	Water Mass Flow (lb/sec)	Air Vol. Flow (m³/sec)	Liquid Vol. Flow (m³/sec)	V_{SG} (m/s)	V_{SL} (m/s)	GLR lab scf/stb	Observed Flow Pattern
test 1	1.52E-02	3.18E-01	5.75E-03	1.44E-04	2.84	7.11E-02	196	IF (Slug)
test 2	6.76E-03	2.99E-01	2.47E-03	1.36E-04	1.22	6.69E-02	89	IF (Slug)
test 3	1.01E-02	3.19E-01	3.82E-03	1.45E-04	1.88	7.15E-02	129	IF (Slug)
test 4	4.37E-03	3.08E-01	1.60E-03	1.39E-04	0.79	6.88E-02	56	IF (Slug)
test 5	4.35E-03	1.24E-01	1.65E-03	5.64E-05	0.81	2.78E-02	143	IF (Slug)
test 6	6.86E-03	1.17E-01	2.61E-03	5.29E-05	1.29	2.61E-02	242	IF (Slug)
test 7	1.02E-02	1.21E-01	3.97E-03	5.50E-05	1.96	2.71E-02	354	IF (Slug)
test 8	1.52E-02	1.19E-01	5.92E-03	5.39E-05	2.92	2.66E-02	539	IF (Slug)
test 9	1.52E-02	4.66E-02	6.04E-03	2.11E-05	2.98	1.04E-02	1401	IF (Slug)
test 10	1.02E-02	4.60E-02	4.01E-03	2.09E-05	1.98	1.03E-02	943	IF (Slug)
test 11	6.97E-03	4.42E-02	2.69E-03	2.00E-05	1.33	9.89E-03	658	IF (Slug)
test 12	4.42E-03	4.36E-02	1.68E-03	1.98E-05	0.83	9.76E-03	416	IF (Slug)
test 13	4.18E-03	1.63E-02	1.61E-03	7.42E-06	0.79	3.66E-03	1063	IF (Slug)
test 14	6.56E-03	1.58E-02	2.53E-03	7.18E-06	1.25	3.54E-03	1731	IF (Slug)
test 15	1.02E-02	1.63E-02	4.06E-03	7.39E-06	2.00	3.65E-03	2694	IF (Slug)
test 16	1.52E-02	1.40E-02	6.08E-03	6.35E-06	3.00	3.13E-03	4695	IF (Slug)

Table 14: Field Case Study (+2° Toe-up condition) with tool in flow loop.

Field Case Parameters					
Case 1		Field Condition (Calculated)		Equivalent Condition	Laboratory
Oil flow rate [STBO/day]	15	v_SL [m/s] =	5.61E-02	v_SL [m/s] =	3.50E-02
Water flow rate [STBW/day]	341	v_SG [m/s] =	4.25E-03	v_SG [m/s] =	8.58E-04
Gas flow rate [SCFD]	9500	dp/dL_G [Pa/m]	-2.22E+01	dp/dL_G [Pa/m]	-3.64E-01
GLR [SCF/STBL]	26.7	X = 45.71			
		Y = -1.76E+6			
Case 2		Field Condition (Calculated)		Equivalent Condition	Laboratory
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	2.24E-01	v_SG [m/s] =	8.46E-01
Gas flow rate [SCFD]	5.00E+04	dp/dL_G [Pa/m]	-2.20E+01	dp/dL_G [Pa/m]	-1.83E-03
Gas flow rate [SCFD]	1000	X = 1.90			
		Y = -1.18E+03			
Case 3		Field Condition (Calculated)		Equivalent Condition	Laboratory
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	4.48E-01	v_SG [m/s] =	1.69E+00
Gas flow rate [SCFD]	1.00E+06	dp/dL_G [Pa/m]	-2.13E+01	dp/dL_G [Pa/m]	8.97E-01
GLR [SCF/STBL]	2000	X = 1.02			
		Y = -3.40E+02			

Table 15: Field Case Study (0°- Horizontal flow) with tool in flow loop.

Field Case Parameters					
Case 1		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	15	v_SL [m/s] =	5.61E-02	v_SL [m/s] =	5.55E-02
Water flow rate [STBW/day]	341	v_SG [m/s] =	4.25E-03	v_SG [m/s] =	2.37E-03
Gas flow rate [SCFD]	9500	dp/dL_G [Pa/m]	3.29E-01	dp/dL_G [Pa/m]	9.72E-01
GLR [SCF/STBL]	26.7	X = 45.72			
		Y = 0			
Case 2		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.55E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	2.24E-01	v_SG [m/s] =	8.82E-01
Gas flow rate [SCFD]	5.00E+04	dp/dL_G [Pa/m]	1.77E+00	dp/dL_G [Pa/m]	2.43E+00
Gas flow rate [SCFD]	1000	X = 1.90			
		Y = 0			
Case 3		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_SL [m/s] =	7.88E-02	v_SL [m/s] =	5.55E-02
Water flow rate [STBW/day]	0	v_SG [m/s] =	4.48E-01	v_SG [m/s] =	1.76E+00
Gas flow rate [SCFD]	1.00E+06	dp/dL_G [Pa/m]	3.12E+00	dp/dL_G [Pa/m]	4.28E+00
GLR [SCF/STBL]	2000	X = 1.02			
		Y = 0			

Table 16: Field Case Study (-1° Toe-down condition) with tool in flow loop.

Field Case Parameters					
Case 1		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	15	v_{SL} [m/s] =	5.61E-02	v_{SL} [m/s] =	3.50E-02
Water flow rate [STBW/day]	341	v_{SG} [m/s] =	4.25E-03	v_{SG} [m/s] =	8.58E-04
Gas flow rate [SCFD]	9500	$X = 45.72$			
GLR [SCF/STBL]	26.7	$Y = 8.79E+5$			
Case 2		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_{SL} [m/s] =	7.88E-02	v_{SL} [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_{SG} [m/s] =	2.24E-01	v_{SG} [m/s] =	8.46E-01
Gas flow rate [SCFD]	5.00E+04	$X = 1.90$			
GLR [SCF/STBL]	1000	$Y = 5.93E+02$			
Case 3		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_{SL} [m/s] =	7.88E-02	v_{SL} [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_{SG} [m/s] =	4.48E-01	v_{SG} [m/s] =	1.69E+00
Gas flow rate [SCFD]	1.00E+06	$X = 1.02$			
GLR [SCF/STBL]	2000	$Y = 1.70E+02$			

Table 17: Field Case Study (-2° Toe-down condition) with tool in flow loop.

Field Case Parameters					
Case 1		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	15	v_{SL} [m/s] =	5.61E-02	v_{SL} [m/s] =	3.50E-02
Water flow rate [STBW/day]	341	v_{SG} [m/s] =	4.25E-03	v_{SG} [m/s] =	8.58E-04
Gas flow rate [SCFD]	9500	$X = 45.72$			
GLR [SCF/STBL]	26.7	$Y = 1.76E+6$			
Case 2		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_{SL} [m/s] =	7.88E-02	v_{SL} [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_{SG} [m/s] =	2.24E-01	v_{SG} [m/s] =	8.46E-01
Gas flow rate [SCFD]	5.00E+04	$X = 1.90$			
GLR [SCF/STBL]	1000	$Y = 1.18E+03$			
Case 3		Field Condition (Calculated)		Equivalent Laboratory Condition	
Oil flow rate [STBO/day]	500	v_{SL} [m/s] =	7.88E-02	v_{SL} [m/s] =	5.32E-02
Water flow rate [STBW/day]	0	v_{SG} [m/s] =	4.48E-01	v_{SG} [m/s] =	1.69E+00
Gas flow rate [SCFD]	1.00E+06	$X = 1.02$			
GLR [SCF/STBL]	2000	$Y = 3.40E+02$			

APPENDIX C

Flow Pattern Prediction using Taitel and Dukler (1976) Model

Taitel and Dukler (1976) model provided several transition boundaries equations for predicting each flow pattern for angle ranging from -10° to $+10^\circ$. Before using the transition boundaries equation to establish the flow pattern for each test conducted in the laboratory, closure relationships were used. The first step to determine the existing flow pattern is to calculate for the superficial Reynold numbers for the liquid and gas phases. The superficial Reynold number for the gas and liquid phases are:

$$Re_{SG} = \frac{\rho_G v_{SG} d}{\mu_G}, \quad Re_{SL} = \frac{\rho_L v_{SL} d}{\mu_L} \quad (18)$$

The superficial Reynold numbers were used to calculate for the superficial fanning friction factors for the liquid and gas phases. The fanning friction factor can be calculated using the Blasius type-equations:

$$f_{SG} = C_G (Re_{SG})^{-m}, \quad f_{SL} = C_L (Re_{SL})^{-n} \quad (19)$$

The next parameters calculated were the Lockhart and Martinelli parameter, X , and the inclination parameter, Y using:

$$X = \sqrt{\frac{\left. \frac{dP}{dL} \right|_{SL}}{\left. \frac{dP}{dL} \right|_{SG}}} = \sqrt{\frac{\frac{4f_{SL}}{d} \left(\frac{\rho_L v_{SL}^2}{2} \right)}{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)}} \quad (20)$$

$$Y = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\left. \frac{dP}{dL} \right|_{SG}} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)} \quad (21)$$

These two dimensionless parameters were used in the dimensionless combined momentum equation to determine the dimensionless liquid level. The dimensionless liquid level was obtained using goal seek in excel. The dimensionless combined momentum equation is expressed as:

$$X^2 \left[(\tilde{v}_L \tilde{d}_L)^{-n} \tilde{v}_L^2 \frac{\tilde{S}_L}{\tilde{A}_L} \right] - \left[(\tilde{v}_G \tilde{d}_G)^{-m} \tilde{v}_G^2 \left(\frac{\tilde{S}_G}{\tilde{A}_G} + \frac{\tilde{S}_I}{\tilde{A}_L} + \frac{\tilde{S}_I}{\tilde{A}_G} \right) \right] + 4Y = 0 \quad (22)$$

Where the dimensionless wetted wall circumference parameter, S , occupied by the liquid, gas and interface respectively can be calculated from:

$$\tilde{S}_L = \pi - \cos^{-1}(2\tilde{h}_L - 1), \quad \tilde{S}_G = \cos^{-1}(2\tilde{h}_L - 1), \quad (23)$$

$$\tilde{S}_I = \sqrt{1 - (2\tilde{h}_L - 1)^2}$$

The dimensionless area for flow of the liquid and gas phases can be computed from:

$$\tilde{A}_L = 0.25(\tilde{S}_L + (2\tilde{h}_L - 1)^2 * \tilde{S}_I), \quad \tilde{A}_G = 0.25(\tilde{S}_G + (2\tilde{h}_L - 1)^2 * \tilde{S}_I) \quad (24)$$

The dimensionless hydraulic diameter, d , for the liquid and gas phases can be calculated from:

$$\tilde{d}_L = \frac{4\tilde{A}_L}{\tilde{S}_L}, \quad \tilde{d}_G = \frac{4\tilde{A}_G}{\tilde{S}_G + \tilde{S}_I} \quad (25)$$

The dimensionless actual velocity, v , for the liquid and gas phases can be calculated from:

$$\tilde{v}_L = \frac{\tilde{A}_p}{\tilde{A}_L}, \quad \tilde{v}_G = \frac{\tilde{A}_p}{\tilde{A}_G} \quad (26)$$

m is an exponent of Blasius type Fanning friction factor equation based on Re_{SG} and n is an exponent of Blasius type Fanning friction factor equation based on Re_{SL} . $m = n = 1$ if $Re < 2100$, and $m = n = 0.2$ if $Re > 2100$.

When the dimensionless liquid level, $\tilde{h}_L$ is obtained, it is then used in dimensionless transition A (stratified to non-stratified flow) criterion form. Transition A boundary criterion is defined as

$$\mathcal{F}^2 \left[\frac{1}{(1 - \tilde{h}_L)^2} \frac{\tilde{v}_G^2 \tilde{S}_I}{\tilde{A}_G} \right] \geq 1 \quad (27)$$

Where $\mathcal{F}$ is defined as: (28)

$$\mathcal{F} = \sqrt{\frac{\rho_G}{(\rho_L - \rho_G)}} \frac{v_{SG}}{\sqrt{d g \cos(\theta)}}$$

If the left-hand side is greater than the right-hand side in Eq. 27, than the flow pattern is non-stratified. However, if the left-hand side is less than the right-hand side in Eq. 27, than the flow pattern is stratified flow.

If the flow pattern is stratified flow from the transition A, then transition C is checked. Transition C is the transition boundary between stratified smooth and stratified wavy for horizontal and upward flow. Transition C criterion expressed in dimensionless form is:

$$K \geq \frac{2}{\sqrt{\tilde{v}_L} \tilde{v}_G \sqrt{s}} \quad (29)$$

Where K is defined as (30)

$$K = \mathcal{F}^2 Re_{SL}$$

And

$$s = 0.01$$

If the left-hand side is greater than the right-hand side in equation 29, than the flow pattern is stratified wavy. However, if the left-hand side is less than the right-hand side in Eq. 29, than the flow pattern is stratified smooth.

For upward flow direction, meaning that the inclination angle is negative (Toe-Down condition), transition K is applied. Transition k is written in term of critical Froude number and its expressed as

$$Fr = \frac{v_L}{\sqrt{g h_L}} > 1.5 \quad (31)$$

If the Froude number in Eq. 31 is greater than 1.5, the flow is stratified wavy. If the Froude number is less than 1.5, then the flow is stratified smooth.

If the flow pattern is non-stratified flow from the transition A, then transition B is checked. Transition B is the boundary transition from intermittent or dispersed bubble flows to annular flow. The transition depends on the dimensionless liquid level, $\tilde{h}_L$, in the pipe. The criterion for transition B is

$$\tilde{h}_L = \frac{h_L}{d} = 0.35 \quad (32)$$

If the dimensionless liquid level in the pipe is greater than 0.35, the flow is slug or dispersed bubble flow. However, if the dimensionless liquid level in the pipe is less than or equal 0.35, the flow pattern is annular flow.

Considering that the flow from Eq. 32 is slug or dispersed bubble flow, then transition D is checked. Transition D is the transition boundary between intermittent and dispersed bubble flow. The criterion for this boundary is defined as

$$\mathcal{T}^2 \geq \frac{8\tilde{A}_G}{\tilde{S}_I \tilde{v}_L^2 (\tilde{v}_L \tilde{d}_L)^{-n}} \quad (33)$$

Where (34)

$$\mathcal{T}^2 = \frac{-\frac{dP}{dL}|_{SL}}{(\rho_L - \rho_G)g\cos(\theta)}$$

If the left-hand side is greater than or equal the right-hand side of Eq. 33, then the flow is dispersed bubble flow. Nevertheless, if the left-hand side is less than the right-hand side, then the flow is slug flow.

APPENDIX D

Pressure drop per unit length Prediction using Taitel and Dukler (1976) Model

For this research work, the pressure drop per unit length calculation was only done for stratified flow. From the experiments conducted, it was observed that the new gas anchor could potentially separate gas from the mixture when stratified flow existed. The pressure drop per unit length for stratified flow can be calculated momentum balance for either the liquid phase or the gaseous phase. The dimensional momentum balance equations for liquid and gas phases are written as:

$$\left. \frac{dP}{dL} \right|_L = - \frac{\tau_{WL} S_L}{A_L} + \frac{\tau_I S_I}{A_L} - \rho_L g \sin(\theta) \quad (35)$$

$$\left. \frac{dP}{dl} \right|_G = - \frac{\tau_{WG} S_G}{A_G} - \frac{\tau_I S_I}{A_G} - \rho_G g \sin(\theta) \quad (36)$$

The combined momentum equation must be solved first to obtain the liquid height and holdup. Then, the geometric parameters such as $\tilde{d}_L$, $\tilde{A}_L$, $\tilde{A}_G$ and $\tilde{S}_I$ can be calculated from equations 23 – 26. The dimensional geometric parameters can be calculated from

$$A_L = \tilde{A}_L d^2, \quad A_G = \tilde{A}_G d^2 \quad (37)$$

The dimensional wetted wall parameter, S , of the liquid, gas and interface can be calculated from

$$S_L = \tilde{S}_L d; \quad S_G = \tilde{S}_G d; \quad S_I = \tilde{S}_I d \quad (38)$$

The next step is to calculate for the wall shear stress, τ , in the gas phase, liquid phase and at the interface. The three equations to calculate for the wall shear stresses for liquid, gas and interface respectively are given as

$$\tau_{WL} = f_L \frac{\rho_L v_L^2}{2}; \quad \tau_{WG} = f_G \frac{\rho_G v_G^2}{2}; \quad \tau_I = f_I \frac{\rho_G (v_G - v_L)^2}{2} \quad (39)$$

The fanning friction factor, f , for the liquid, and gas phases respectively can be obtained from the following equations

$$f_L = C_L (Re_L)^{-n}; \quad f_G = C_G (Re_G)^{-m}; \quad (40)$$

The fanning friction factor for the interface, f_I , is assumed as the following:

$$f_I = f_G \text{ for stratified flow regime}$$

and

$$f_I = 0.0142 \text{ for stratified wavy}$$

m is an exponent of Blasius type Fanning friction factor equation based on Re_{SG} and n is an exponent of Blasius type Fanning friction factor equation based on Re_{SL} . $m = n = 1$ if $Re < 2100$, and $m = n = 0.2$ if $Re > 2100$.

C is a constant whose values depends on either Re_{SL} or Re_{SG} . 1 for laminar flow $Re < 2100$ and 0.046 for turbulent flow $Re > 2100$

The actual Reynold number for the liquid and gas phases respectively can be calculated from

$$Re_L = \frac{\rho_L v_L d_L}{\mu_L}; \quad Re_G = \frac{\rho_G v_G d_G}{\mu_G}, \quad (41)$$

Where the dimensional hydraulic diameter, d , for both the liquid and gaseous phases can be determine from

$$d_L = \frac{4A_L}{S_L}, \quad \tilde{d}_G = \frac{4A_G}{S_G + S_I} \quad (42)$$

And the actual velocities for both the liquid and gaseous phases can be calculated from

$$v_L = \frac{v_{SL}}{H_L}, \quad v_G = \frac{v_{SG}}{1 - H_L} \quad (43)$$

Lastly, the liquid holdup, H_L , can be calculated from

$$H_L = \frac{A_L}{A_p} \quad (44)$$

Field Case Prediction using Lockhart and Martinelli parameter, X , and inclination angle parameter, Y .

Three cases were done for the field case study for the inclination angles ($+2^\circ$, $+1^\circ$, 0° , -1° , and -2°) performed in the laboratory. In this model, we matched the X , and Y , values of the field to laboratory X , and Y , values. This matching enables us to determine the equivalent v_{SL} and v_{SG} values for the laboratory condition in all three cases.

The first step is to use the given field parameters including the liquid (oil & water) and gas flow rates, GLR, casing ID, liquid and gas formation volume factors to determine the superficial liquid and gas velocities. The field liquid and gas superficial velocities can be calculated from

$$v_{SL} = \frac{Q_L}{A_P}; \quad v_{SG} = \frac{Q_G}{A_P}, \quad (45)$$

The next step is to calculate for the superficial Reynold number for the gas and liquid phase for field condition. The superficial Reynold numbers for the liquid and gas can be obtained from

$$Re_{SG} = \frac{\rho_G v_{SG} d}{\mu_G}, \quad Re_{SL} = \frac{\rho_L v_{SL} d}{\mu_L} \quad (46)$$

The Re_{SG} and Re_{SL} values were used to calculate for the superficial fanning friction factor values for both liquid and gaseous phase. Eq. 47 provides the equations for calculating the superficial fanning friction factor values for the liquid and gaseous phases respectively for field condition.

$$f_{SG} = C_G (Re_{SG})^{-m}, \quad f_{SL} = C_L (Re_{SL})^{-n} \quad (47)$$

The next parameters calculated were the field Lockhart and Martinelli parameter, X , and the inclination parameter, Y using:

$$X = \frac{\sqrt{\frac{dP}{dL}|_{SL}}}{\sqrt{\frac{dP}{dL}|_{SG}}} = \sqrt{\frac{\frac{4f_{SL}}{d}(\frac{\rho_L v_{SL}^2}{2})}{\frac{4f_{SG}}{d}(\frac{\rho_G v_{SG}^2}{2})}} \quad (48)$$

$$Y = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\frac{dP}{dL}|_{SG}} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\frac{4f_{SG}}{d}(\frac{\rho_G v_{SG}^2}{2})} \quad (49)$$

After obtaining the X and Y values for the field case, back-calculation was performed to get the equivalent v_{SG} and v_{SL} for the laboratory condition.

First, the Eq. 49 were manipulated to find the superficial gas pressure drop per unit length, $\frac{dP}{dL}|_{SG}$, for laboratory condition. The superficial gas pressure drop per unit length for laboratory condition can be expressed as

$$\frac{dP}{dL}|_{SG} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{Y} \quad (50)$$

Y is the calculated field inclination angle parameter. ρ_L and ρ_G are the liquid and gas densities for the laboratory condition. g is a constant whose values is 9.81 m/s and θ is the inclination angles (+2°, +1°, 0°, -1°, and -2°)

The next step is to calculate for the superficial liquid pressure drop per unit length, $\frac{dP}{dL}|_{SL}$, for laboratory condition. This can be achieved by manipulating Eq. 48 into the below expression.

$$\frac{dP}{dL}|_{SL} = X^2 \cdot \frac{dP}{dL}|_{SG} \quad (51)$$

GRG Nonlinear solver was used to calculate for the equivalent v_{SG} and v_{SL} simultaneously for the laboratory condition. Initial guess values for v_{SG} and v_{SL} were assumed to be 0.1. The superficial Reynold numbers for liquid and gaseous phases were calculated using

$$Re_{SG} = \frac{\rho_G v_{SG} d}{\mu_G}, \quad Re_{SL} = \frac{\rho_L v_{SL} d}{\mu_L} \quad (52)$$

The initial v_{SG} and v_{SL} were used in Eq. 52. The superficial fanning friction values for both the liquid and gaseous phases were calculated using

$$f_{SG} = C_G (Re_{SG})^{-m}, \quad f_{SL} = C_L (Re_{SL})^{-n} \quad (53)$$

The next thing is to calculate for the Lockhart and Martinelli parameter, X , and the inclination parameter, Y at laboratory condition using

$$X = \frac{\sqrt{\left. \frac{dP}{dL} \right|_{SL}}}{\sqrt{\left. \frac{dP}{dL} \right|_{SG}}} = \sqrt{\frac{\frac{4f_{SL}}{d} \left(\frac{\rho_L v_{SL}^2}{2} \right)}{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)}} \quad (54)$$

$$Y = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\left. \frac{dP}{dL} \right|_{SG}} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\frac{4f_{SG}}{d} \left(\frac{\rho_G v_{SG}^2}{2} \right)} \quad (55)$$

The process of finding the equivalent laboratory v_{SG} and v_{SL} values is an iterative process. It starts with assuming an initial v_{SG} and v_{SL} values and calculating from Eq. 52 to Eq. 55, until the X and Y values at laboratory condition match with the field X and Y values.

BIOGRAPHY

Isaac D. G. Karmon, II. was born in Monrovia, Liberia, in 1984. He received the B.Sc. in biology from the University of Liberia, Monrovia, Liberia, in 2009 and the M.P.H. in epidemiology from Cuttington University Graduate School, Monrovia, Liberia, in 2012. In January 2014, he moved to the United State of America to pursue his B.Sc. and M.Sc. in petroleum engineering. He obtained the B.Sc. degree in petroleum engineering from the Texas Tech University, Lubbock, Texas, USA in May 2017. In May 2019, he received the M.Sc. degree in petroleum engineering from the Texas Tech University, Lubbock, Texas, USA. His current research work focuses on downhole gas separation in horizontal wells. His research interest covers the quantifying of a new horizontal well gas anchor performance, with a technical publication (SPE-195198-MS).

Mr. Karmon has worked in the oil and gas downstream sector for over three years. He served as Assistant operation Manager of the Liberia Petroleum Refining Company, Monrovia, Liberia in 2013 before moving to the USA to further his education. He is a member of the Society for Petroleum Engineers (SPE), and the American Association for Drilling Engineers (AADE).